REQUEST:

Please provide copies of the financial statements (balance sheet, income statement, statement of cash flows, and the notes to the financial statements) for Applicant for 2010, 2011 and 2012, when available. Please provide copies of the financial statements in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

RESPONSE:

Please see Attachment 1 through Attachment 3 for the Form 10-K's for fiscal years 2010, 2011 and 2012, which include the Company's balance sheet, income statement and statement of cash flows.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, OAG_1-188_Att1 - 09-30-10 Form 10-K.pdf, 146 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, OAG_1-188_Att2 - 09-30-11 Form 10-K.pdf, 144 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, OAG_1-188_Att3 - 09-30-12 Form 10-K.pdf, 131 Pages.

Respondent: Jason Schneider

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(Zip code)*

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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

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

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

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2010, was $2,598,503,183.

As of November 5, 2010, the registrant had 90,421,614 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 9, 2011 are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky 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.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
Settled Cities	Represents 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
SRF	Stable Rate Filing
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
WNA	Weather Normalization Adjustment

PART I

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

ITEM 1. *Business.*

Overview and Strategy

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

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

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

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have continued to grow our earnings after giving effect to our acquisitions and have experienced more than 25 consecutive years of increasing dividends and earnings. Historically, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. In recent years, we have also achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations.

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

Operating Segments

We operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.

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

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

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

- Atmos Energy Mid-Tex Division,
- Atmos Energy Kentucky/Mid-States Division,
- Atmos Energy Louisiana Division,
- Atmos Energy West Texas Division,
- Atmos Energy Colorado-Kansas Division and
- Atmos Energy Mississippi Division

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

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

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

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

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

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for approximately 94 percent of residential and commercial margins in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

As of September 30, 2010 we had WNA for our residential and commercial meters in the following service areas for the following periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
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 consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. 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.

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 2010 were Anadarko Energy Services, BP Energy Company, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, ONEOK Energy Services Company L.P., Tenaska Marketing, Texla Energy Management, Inc. 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 2010 was on January 8, 2010, when sales to customers reached approximately 4.0 Bcf.

Currently, all of our natural gas distribution divisions, except for our Mid-Tex Division, utilize 39 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 solely by our Atmos Pipeline — Texas Division.

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 regulations or statutes. 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 September 30, 2010, we held 1,115 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

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

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

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

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

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, the West Texas Division entered into agreements with its West Texas service areas during 2008 and its Amarillo and Lubbock service areas during 2009 to update rates for customers in these service areas through an annual rate review mechanism.

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

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.

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/GRIP Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/24/2004	$417,111	8.258%	10.00%
Atmos Pipeline — Texas — GRIP	Texas	04/20/2010	799,841	8.258%	10.00%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	08/01/2010	144,583	(2)	(2)
Kentucky/Mid-States	Georgia	03/31/2010	88,583(3)	8.61%	10.70%
	Illinois	11/01/2000	24,564	9.18%	11.56%
	Iowa	03/01/2001	5,000	(2)	11.00%
	Kentucky	06/01/2010	184,697	(2)	(2)
	Missouri	09/01/2010	66,459	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2010	96,400	8.22%	10.00% - 10.80%
	LGS	07/01/2010	251,591	8.54%	10.40%
Mid-Tex — Settled Cities	Texas	10/01/2010	(2)	8.19%	9.60%
Mid-Tex — Dallas & Environs . .	Texas	01/26/2010	1,279,647(4)	8.60%	10.40%
Mid-Tex — Dallas & Environs — GRIP.	Texas	09/01/2010	1,283,357(4)	8.60%	10.40%
Mississippi	Mississippi	12/15/2009	227,055	8.27%	10.04%
West Texas	Amarillo	08/01/2010	55,537	8.19%	9.60%
	Lubbock	09/01/2010	57,074	8.19%	9.60%
	West Texas	08/15/2010	135,565	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[5]	WNA	Performance-Based Rate Program[6]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[7]	No	No	110,646
	Kansas	(2)	Yes	Yes	No	128,640
Kentucky/Mid-States	Georgia	52/48	No	Yes	Yes	64,946
	Illinois	67/33	No	No	No	22,868
	Iowa	57/43	No	No	No	4,300
	Kentucky	(2)	Yes	Yes	Yes	176,634
	Missouri	49/51	No	No	No	56,843
	Tennessee	52/48	Yes	Yes	Yes	132,261
	Virginia	51/49	Yes	Yes	No	23,163
Louisiana.	Trans LA	52/48	No	Yes	No	76,653
	LGS	52/48	No	Yes	No	277,551
Mid-Tex — Settled Cities	Texas	52/48	Yes	Yes	No	1,236,538
Mid-Tex — Dallas & Environs	Texas	51/49	Yes	Yes	No	309,134
Mississippi	Mississippi	52/48	No	Yes	No	266,233
West Texas	Amarillo	52/48	Yes	Yes	No	70,578
	Lubbock	52/48	Yes	Yes	No	73,810
	West Texas	52/48	Yes	Yes	No	155,242

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

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

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $28.4 million included in the October 2010 Pipeline Replacement Program (PRP) surcharge. The $28.4 million of the Georgia rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2010, an authorized rate of return of 8.56 percent and an authorized return on equity of 10.70 percent.

(4) The Mid-Tex Rate Base amounts for the Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

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

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

(7) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Natural Gas Distribution Sales and Statistical Data

	Fiscal Year Ended September 30				
	2010	2009	2008	2007	2006
METERS IN SERVICE, end of year					
Residential	2,910,672	2,901,577	2,911,475	2,893,543	2,886,042
Commercial	262,778	265,843	268,845	272,081	275,577
Industrial	2,090	2,193	2,241	2,339	2,661
Public authority and other	10,500	9,231	9,218	19,164	16,919
Total meters	3,186,040	3,178,844	3,191,779	3,187,127	3,181,199
INVENTORY STORAGE BALANCE — Bcf	54.3	57.0	58.3	58.0	59.9
HEATING DEGREE DAYS[1]					
Actual (weighted average)	2,780	2,713	2,820	2,879	2,527
Percent of normal	102%	100%	100%	100%	87%
SALES VOLUMES — MMcf[2]					
Gas Sales Volumes					
Residential	190,424	159,762	163,229	166,612	144,780
Commercial	103,028	91,379	93,953	95,514	87,006
Industrial	19,047	18,563	21,734	22,914	26,161
Public authority and other	10,129	12,413	13,760	12,287	14,086
Total gas sales volumes	322,628	282,117	292,676	297,327	272,033
Transportation volumes	135,865	130,691	141,083	135,109	126,960
Total throughput	458,493	412,808	433,759	432,436	398,993
OPERATING REVENUES (000's)[2]					
Gas Sales Revenues					
Residential	$1,826,752	$1,830,140	$2,131,447	$1,982,801	$2,068,736
Commercial	808,981	838,184	1,077,056	970,949	1,061,783
Industrial	112,366	135,633	212,531	195,060	276,186
Public authority and other	70,580	89,183	137,821	114,298	144,600
Total gas sales revenues	2,818,679	2,893,140	3,558,855	3,263,108	3,551,305
Transportation revenues	62,254	59,914	60,504	59,813	62,215
Other gas revenues	31,560	31,711	35,771	35,844	37,071
Total operating revenues	$2,912,493	$2,984,765	$3,655,130	$3,358,765	$3,650,591
Average transportation revenue per Mcf	$ 0.46	$ 0.46	$ 0.43	$ 0.44	$ 0.49
Average cost of gas per Mcf sold	$ 5.77	$ 6.95	$ 9.05	$ 8.09	$ 10.02
Employees	4,714	4,691	4,558	4,472	4,402

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data by Division

	Fiscal Year Ended September 30, 2010							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Colorado-Kansas	Mississippi	Other[3]	Total
METERS IN SERVICE								
Residential	1,429,287	424,048	331,784	271,418	216,831	237,304	—	2,910,672
Commercial	116,240	52,938	22,420	24,919	20,741	25,520	—	262,778
Industrial	145	862	—	484	86	513	—	2,090
Public authority and other	—	2,733	—	2,809	2,062	2,896	—	10,500
Total	1,545,672	480,581	354,204	299,630	239,720	266,233	—	3,186,040
HEATING DEGREE DAYS[1]								
Actual	2,100	3,924	1,532	3,537	5,909	2,734	—	2,780
Percent of normal	103%	100%	96%	99%	106%	102%	—	102%
SALES VOLUMES — MMcf[2]								
Gas Sales Volumes								
Residential	92,489	27,917	15,810	19,772	18,661	15,775	—	190,424
Commercial	55,916	16,841	7,821	7,892	7,349	7,209	—	103,028
Industrial	3,227	5,931	—	4,317	148	5,424	—	19,047
Public authority and other	—	1,444	—	3,482	2,100	3,103	—	10,129
Total	151,632	52,133	23,631	35,463	28,258	31,511	—	322,628
Transportation volumes	45,822	43,782	5,626	22,429	12,655	5,551	—	135,865
Total throughput	197,454	95,915	29,257	57,892	40,913	37,062	—	458,493
OPERATING MARGIN (000's)[2]	$ 475,852	$169,516	$123,344	$105,476	$ 81,056	$ 94,203	$ —	$1,049,447
OPERATING EXPENSES (000's)[2]								
Operation and maintenance	$ 145,166	$ 63,665	$ 43,604	$ 36,696	$ 31,233	$ 41,542	$ 976	$ 362,882
Depreciation and amortization	$ 89,411	$ 33,267	$ 22,986	$ 15,881	$ 16,352	$ 12,621	$ —	$ 190,518
Taxes, other than income	$ 106,620	$ 14,718	$ 10,995	$ 19,390	$ 8,271	$ 13,599	$ —	$ 173,593
OPERATING INCOME (000's)[2]	$ 134,655	$ 57,866	$ 45,759	$ 33,509	$ 25,200	$ 26,441	$ (976)	$ 322,454
CAPITAL EXPENDITURES (000's)	$ 196,109	$ 62,808	$ 47,193	$ 39,387	$ 29,792	$ 28,538	$ 33,988	$ 437,815
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$1,761,087	$750,225	$413,189	$319,053	$300,380	$284,195	$130,983	$3,959,112
OTHER STATISTICS, at year end								
Miles of pipe	29,156	12,196	8,381	7,666	7,175	6,546	—	71,120
Employees	1,650	587	439	344	284	371	1,039	4,714

See footnotes following these tables.

	Fiscal Year Ended September 30, 2009							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Colorado-Kansas	Mississippi	Other(3)	Total
METERS IN SERVICE								
Residential	1,417,869	423,829	333,224	270,757	218,609	237,289	—	2,901,577
Commercial	116,480	53,386	22,769	24,986	22,080	26,142	—	265,843
Industrial	148	909	—	508	96	532	—	2,193
Public authority and other	—	2,555	—	2,839	1,015	2,822	—	9,231
Total	1,534,497	480,679	355,993	299,090	241,800	266,785	—	3,178,844
HEATING DEGREE DAYS(1)								
Actual	2,036	3,853	1,574	3,553	5,520	2,746	—	2,713
Percent of normal	100%	98%	101%	99%	100%	103%	—	100%
SALES VOLUMES — MMcf(2)								
Gas Sales Volumes								
Residential	73,678	26,589	12,371	16,341	17,280	13,503	—	159,762
Commercial	48,363	16,049	6,771	6,780	6,848	6,568	—	91,379
Industrial	2,918	6,217	—	3,528	196	5,704	—	18,563
Public authority and other	—	1,434	—	6,014	2,064	2,901	—	12,413
Total	124,959	50,289	19,142	32,663	26,388	28,676	—	282,117
Transportation volumes	44,991	41,693	5,151	23,417	10,471	4,968	—	130,691
Total throughput	169,950	91,982	24,293	56,080	36,859	33,644	—	412,808
OPERATING MARGIN (000's)(2)	$ 483,155	$163,602	$118,021	$ 89,982	$ 78,188	$ 91,680	$ —	$1,024,628
OPERATING EXPENSES (000's)(2)								
Operation and maintenance	$ 150,978	$ 68,823	$ 41,956	$ 35,126	$ 32,935	$ 43,642	$ (4,031)	$ 369,429
Depreciation and amortization	$ 94,040	$ 32,755	$ 22,492	$ 15,242	$ 15,334	$ 12,411	$ —	$ 192,274
Taxes, other than income	$ 108,412	$ 13,261	$ 9,629	$ 15,863	$ 8,222	$ 13,925	$ —	$ 169,312
Asset impairments	$ 2,100	$ 785	$ 510	$ 413	$ 376	$ 415	$ —	$ 4,599
OPERATING INCOME (000's)(2)	$ 127,625	$ 47,978	$ 43,434	$ 23,338	$ 21,321	$ 21,287	$ 4,031	$ 289,014
CAPITAL EXPENDITURES (000's)	$ 173,201	$ 57,943	$ 42,626	$ 33,960	$ 24,726	$ 22,173	$ 24,871	$ 379,500
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$1,615,900	$722,530	$390,957	$299,242	$284,398	$266,053	$124,391	$3,703,471
OTHER STATISTICS, at year end								
Miles of pipe	28,996	12,158	8,321	7,702	7,162	6,540	—	70,879
Employees	1,585	605	446	352	290	389	1,024	4,691

Notes to preceding tables:

(1) 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.

(2) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.

(3) The Other column represents our shared services function, which provides administrative and other support to the Company. Certain costs incurred by this function are not allocated.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of excess gas. 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. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. Rates are updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. Atmos Pipeline — Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

These operations include 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

	Fiscal Year Ended September 30				
	2010	2009	2008	2007	2006
CUSTOMERS, end of year					
Industrial	65	68	62	65	67
Other	176	168	189	196	178
Total	241	236	251	261	245
PIPELINE TRANSPORTATION VOLUMES — MMcf[1]	634,885	706,132	782,876	699,006	581,272
OPERATING REVENUES (000's)[1]	$203,013	$209,658	$195,917	$163,229	$141,133
Employees, at year end	62	62	60	54	85

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

Natural Gas Marketing Segment Overview

Our natural gas marketing activities are conducted through Atmos Energy Marketing (AEM), which is wholly-owned by Atmos Energy Holdings, Inc. (AEH). AEH is a wholly-owned subsidiary of AEC and operates primarily in the Midwest and Southeast areas of the United States.

AEM's primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. In addition, AEM utilizes proprietary and customer-owned transportation and storage assets to provide various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. AEM serves most of its customers under contracts generally having one to two year terms and sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms ranging from 30 days to two years. As a result, AEM's margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEM also seeks to maximize, through asset optimization activities, the economic value associated with the storage and transportation capacity we own or control in our natural gas distribution and natural gas marketing segments. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEM has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

Natural Gas Marketing Sales and Statistical Data

	Fiscal Year Ended September 30				
	2010	**2009**	**2008**	**2007**	**2006**
CUSTOMERS, end of year					
Industrial	652	631	624	677	679
Municipal	61	63	55	68	73
Other	339	321	312	281	289
Total	1,052	1,015	991	1,026	1,041
INVENTORY STORAGE BALANCE — Bcf	15.8	17.0	11.0	19.3	15.3
NATURAL GAS MARKETING SALES VOLUMES — MMcf[1]	420,203	441,081	457,952	423,895	336,516
OPERATING REVENUES (000's)[1]	$2,151,264	$2,336,847	$4,287,862	$3,151,330	$3,156,524

[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), which is wholly-owned by AEH. APS is engaged in nonregulated transmission, storage and natural gas gathering services. Its primary asset is a proprietary 21 mile pipeline located in New Orleans, Louisiana. It also owns or controls additional pipeline and storage capacity including interests in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods.

APS' primary business is to provide storage and transportation services to our Louisiana and Kentucky/ Mid-States regulated natural gas distribution divisions, to our natural gas marketing segment and, on a more limited basis, to third parties. APS earns transportation fees and storage demand charges to aggregate and provide gas supply, provide access to storage capacity and transport gas for these customers.

APS also engages in various asset optimization activities. APS' primary asset optimization activity involves the administration of two asset management plans with regulated affiliates of the Company. These arrangements provide APS the opportunity to maximize the economic value associated with the transportation and storage capacity assigned to these plans. APS attempts to meet this objective through a variety of activities including engaging in natural gas storage transactions and utilizing excess asset capacity to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. These plans require APS to share a portion of the economic value created by these activities with the regulated customers served by these affiliates. These arrangements have been approved by applicable state regulatory commissions and are subject to annual regulatory review intended to ensure proper allocation of economic value between our regulated customers and APS.

APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which APS has access and, in transactions involving storage capacity, selling financial instruments at advantageous prices to lock in a gross profit margin.

Pipeline, Storage and Other Sales and Statistical Data

	Fiscal Year Ended September 30				
	2010	**2009**	**2008**	**2007**	**2006**
OPERATING REVENUES (000's)[1]	$35,318	$41,924	$31,709	$33,400	$25,574
PIPELINE TRANSPORTATION VOLUMES — MMcf[1]	7,375	6,395	5,492	7,710	9,712
INVENTORY STORAGE BALANCE — Bcf	2.1	2.9	1.4	2.0	2.6

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

Ratemaking Activity

Overview

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

Our current rate strategy is to focus on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins. Atmos Energy has annual ratemaking mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately two-thirds of our gross margin. We also have accelerated recovery of only capital for approximately 20 percent of our gross margin. Combined, we have rate structures with accelerated recovery of all or a portion of our expenditures for over 80 percent of our gross margin. Additionally, we have WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 94 percent of our gross margin. Finally, we have the ability to recover the gas cost portion of bad debts for approximately 70 percent of our gross margin. These mechanisms work in tandem to provide insulation from volatile margins, both for the Company and our customers.

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

Although substantial progress has been made in recent years by improving rate design across Atmos' operating areas, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our natural gas distribution revenues in the fiscal years ended September 30, 2010, 2009 and 2008 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $56.8 million, $54.4 million and $40.6 million, became effective in fiscal 2010, 2009 and 2008 as summarized below:

Rate Action	Annual Increase to Operating Income For the Fiscal Year Ended September 30 2010	2009	2008
		(In thousands)	
Rate case filings	$23,663	$ 2,959	$27,838
GRIP filings	16,751	11,443	8,101
Annual rate filing mechanisms	13,757	38,764	3,275
Other rate activity	2,630	1,237	1,424
	$56,801	$54,403	$40,638

Additionally, the following ratemaking efforts were initiated during fiscal 2010 but had not been completed as of September 30, 2010:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Atmos Pipeline — Texas	Rate Case	Texas Railroad Commission	$38,922
Kentucky/Mid-States	PRP Surcharge[1]	Georgia	764
Mississippi	Stable Rate Filing	Mississippi	—
Mid-Tex[2]	Rate Review Mechanism	Settled Cities	56,827
			$96,513

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Company filed a Rate Review Mechanism (RRM) with the Mid-Tex Settled Cities requesting an operating income increase of $56.8 million. A settlement was reached, effective October 1, 2010, which resolves all issues in the annual RRM filing and increases operating income by $23.1 million. Additionally, the settlement allows the Mid-Tex Division to expand its existing program to replace steel service lines which will replace approximately 100,000 steel service lines by September 30, 2012 at a total projected capital cost of $80-$120 million, utilizing an authorized return on equity of 9.0 percent, with the equity portion of the return based on the actual capital structure up to a maximum of 50 percent.

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

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

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas[1]	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	
2009 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 2,513	04/01/2009
West Texas	Texas	446	Various
Total 2009 Rate Case Filings		$ 2,959	
2008 Rate Case Filings:			
Kentucky/Mid-States	Virginia	$ 869	09/30/2008
Kentucky/Mid-States	Georgia	3,351	09/22/2008
Mid-Tex[2]	Texas	5,430	06/24/2008
Colorado-Kansas	Kansas	2,100	05/12/2008
Mid-Tex[3]	Texas	8,000	04/01/2008
Kentucky/Mid-States	Tennessee	8,088	11/04/2007
Total 2008 Rate Case Filings		$27,838	

(1) In its final order, the Railroad Commission of Texas (RRC) approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

(2) Increase relates only to the City of Dallas and the unincorporated areas of the Mid-Tex Division.

(3) Increase relates only to the Settled Cities area of the Mid-Tex Division.

GRIP Filings

As discussed above in "Natural Gas Distribution Segment Overview," GRIP allows natural gas utility companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. The following table summarizes our GRIP filings with effective dates during the fiscal years ended September 30, 2010, 2009 and 2008:

Division	Calendar Year	Incremental Net Utility Plant Investment	Additional Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2010 GRIP:				
Mid-Tex[1]	2009	$ 16,957	$ 2,983	09/01/2010
West Texas	2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	2009	95,504	13,405	04/20/2010
Total 2010 GRIP		$131,619	$16,751	
2009 GRIP:				
Mid-Tex[2]	2008	$105,777	$ 2,732	09/09/2009
Atmos Pipeline — Texas	2008	51,308	6,342	04/28/2009
Mid-Tex[1]	2007	57,385	1,837	01/26/2009
West Texas[3]	2007/08	27,425	532	Various
Total 2009 GRIP		$241,895	$11,443	
2008 GRIP:				
Atmos Pipeline — Texas	2007	$ 46,648	$ 6,970	04/15/2008
West Texas	2006	7,022	1,131	12/17/2007
Total 2008 GRIP		$ 53,670	$ 8,101	

(1) Increase relates to the City of Dallas and Environs areas of the Mid-Tex Division.

(2) Increase relates only to the City of Dallas area of the Mid-Tex Division.

(3) The West Texas Division files GRIP applications related only to the Lubbock Environs and the West Texas Cities Environs. GRIP implemented for this division include investments that related to both calendar years 2007 and 2008. The incremental investment is based on system-wide plant and additional annual operating revenue is applicable to environs customers only.

Annual Rate Filing Mechanisms

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

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income (In thousands)	Effective Date
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	
2009 Filings:				
Mid-Tex	Settled Cities	12/31/2008	$ 1,979	08/01/2009
West Texas	WT Cities	12/31/2008	6,599	08/01/2009
Louisiana	LGS	12/31/2008	3,307	07/01/2009
Louisiana	TransLa	09/30/2008	611	04/01/2009
Mississippi	Mississippi	06/30/2008	—	N/A
Mid-Tex	Settled Cities	12/31/2007	21,800	11/08/2008
West Texas	WT Cities	12/31/2007	4,468	11/20/2008
Total 2009 Filings			$38,764	
2008 Filings:				
Louisiana	LGS	12/31/2007	$ 1,709	07/01/2008
Louisiana	TransLa	09/30/2007	1,566	04/01/2008
Total 2008 Filings			$ 3,275	

In August 2010, we reached an agreement to extend the rate review mechanism in our Mid-Tex Division for an additional two-year period beginning October 1, 2010; however, the Mid-Tex Division will be required to file a general system-wide rate case on or before June 1, 2013. This extension provides for an annual rate adjustment to reflect changes in the Mid-Tex Division's costs of service and additions to capital investment from year to year, without the necessity of filing a general rate case.

The settlement also allows us to expand our existing program to replace steel service lines in the Mid-Tex Division's natural gas delivery system. On October 13, 2010, the City of Dallas approved the recovery of the return, depreciation and taxes associated with the replacement of 100,000 steel service lines across the Mid-Tex Division by September 30, 2012. The RRM in the Mid-Tex Division was entered into as a result of a settlement in the September 20, 2007 Statement of Intent case filed with all Mid-Tex Division cities. Of the 440 incorporated cities served by the Mid-Tex Division, 439 of these cities are part of the rate review mechanism process.

The West Texas rate review mechanism was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock and Amarillo rate review mechanisms were entered into in the spring of 2009. The West Texas Coalition of Cities agreed to extend its RRM for one additional cycle as part of the settlement of this year's filing.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2010, 2009 and 2008:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2010 Other Rate Activity:				
Kentucky/Mid-States.	Missouri	ISRS(1)	$ 563	03/02/2010
Colorado-Kansas	Kansas	Ad Valorem(2)	392	01/05/2010
Colorado-Kansas	Kansas	GSRS(3)	766	12/12/2009
Kentucky/Mid-States.	Georgia	PRP Surcharge(4)	909	10/01/2009
Total 2010 Other Rate Activity . . .			$ 2,630	
2009 Other Rate Activity:				
Colorado-Kansas	Kansas	Tax Surcharge(5)	$ 631	02/01/2009
Kentucky/Mid-States.	Missouri	ISRS(1)	408	11/04/2008
Kentucky/Mid-States.	Georgia	PRP Surcharge(4)	198	10/01/2008
Total 2009 Other Rate Activity . . .			$ 1,237	
2008 Other Rate Activity:				
West Texas.	Triangle	Special Contract	$ 748	06/01/2008
Colorado-Kansas	Kansas	Tax Surcharge(5)	1,434	01/01/2008
Colorado-Kansas	Colorado	Agreement(6)	(1,100)	11/20/2007
Kentucky/Mid-States.	Georgia	PRP Surcharge(4)	342	10/01/2007
Total 2008 Other Rate Activity . . .			$ 1,424	

(1) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

(4) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(5) In the state of Kansas, the tax surcharge represents a true-up of ad valorem taxes paid versus what is designed to be recovered through base rates.

(6) In November 2007, the Colorado Public Utilities Commission approved an earnings agreement entered into jointly between the Colorado-Kansas Division, the Commission Staff and the Office of Consumer Counsel. The agreement called for a one-time refund to customers of $1.1 million made in January 2008.

Other Regulation

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

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity, as well as authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. We currently have an existing RRM that should allow us to recover the replacement costs through the end of fiscal 2012. On September 10, 2010, the Texas Railroad Commission (RRC) published for comment a proposed regulation dealing with distribution facility replacement. The proposed regulation would require each gas distribution system operator to develop a risk-based program for the removal or replacement of distribution facilities, including steel service lines. A number of Texas operators, industry groups and facility component manufacturers filed comments. The RRC is presently reviewing the comments with action related to this proposal anticipated later this year or early next year. We are committed to replacing the steel service lines on an accelerated schedule to ensure the safety and reliability of our distribution system, and as part of this commitment, we support the objectives of proposed rulemaking by the RRC for steel service-line replacements statewide. Due to the preliminary status of the rulemaking process, we cannot accurately anticipate the impact the proposed regulation would have on the Company, if adopted, or the expected cost of the replacement program.

Competition

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

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last two years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2010, we had 4,913 employees, consisting of 4,776 employees in our regulated operations and 137 employees in our nonregulated operations.

Available Information

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

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

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2010, Robert W. Best, certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors.*

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

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

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

Historically, we have accessed the commercial paper markets to finance our short-term working capital needs. The disruptions in the credit markets during the fall of 2008 temporarily limited our access to the commercial paper markets and increased our borrowing costs. Consequently, for a short period, we were forced to borrow directly under our primary credit facility that backstops our commercial paper program to provide much of our working capital. This credit facility provides up to $567 million in committed financing through its expiration in December 2011. Our borrowings under this facility, along with our commercial paper, have been used primarily to purchase natural gas supplies for the upcoming winter heating season. The amount of our working capital requirements in the near-term will depend primarily on the market price of natural gas. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations. We have historically supplemented our commercial paper program with a short-term committed credit facility. No borrowings are currently outstanding under our current $200 million short-term facility, which was scheduled to mature in October 2010. In October 2010, this facility was replaced with a $200 million 180-day facility which expires in April 2011, on substantially the same terms.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. If adverse credit conditions were to cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. Such a downgrade could further limit our access to public and/or private credit markets and increase the costs of borrowing under each source of credit.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our natural gas marketing segment because the commodity financial instruments markets could become unavailable to us. Our natural gas marketing segment depends primarily upon a committed credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. A significant reduction in the availability of this facility could require us to provide extra liquidity to support its operations or reduce some of the activities of our natural gas marketing segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

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

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

The slowdown in the U.S. economy, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in improving current economic conditions, including the lowering of current high unemployment rates across the U.S. As a result, our customers may seek to use even less gas and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of the health care benefits for our employees.

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

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years. Although the full effects of the legislation should not impact the Company until 2014, the future cost of compliance with the provisions of the Health Care Reform Act is difficult to measure at this time.

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

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics 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, particularly in our nonregulated business segments, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segments 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. 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. 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. 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 before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match 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. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our natural gas marketing and pipeline, storage and other segments.

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

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

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

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

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 77,000 miles of pipeline and distribution lines. The steel service line replacement program currently underway in our Mid-Tex Division typifies the preventive maintenance and continual renewal that we perform on our natural gas distribution system in all 12 states in which we operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the recent unfortunate pipeline incident in California, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Accordingly, the costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

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

FERC has regulatory authority that affects some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. We are currently under investigation by FERC for possible violations of its posting and competitive bidding regulations for pre-arranged released firm capacity on interstate natural gas pipelines. Should FERC conclude that we have committed such violations of its regulations and levies substantial fines and/or penalties against us, our business, financial condition or financial results could be adversely affected. In addition, although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

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.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of new federal and state legislative and regulatory initiatives proposed in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. For example, in June 2009, the U.S. House of Representatives approved *The American Clean Energy and Security Act of 2009*, also known as the Waxman-Markey bill or "cap and trade" bill. However, neither this bill nor a related bill in the U.S. Senate, the Clean Energy and Emissions Power Act was passed by Congress. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

Over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

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

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

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

Rapid increases in the costs of purchased gas would 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 enable us to serve any 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. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures during the next two fiscal years in executing our steel service line replacement program in the Mid-Tex Division. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

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

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last two years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

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

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

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

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

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2010, our natural gas distribution segment owned an aggregate of 71,120 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 5,924 miles of gas transmission and gathering lines and our pipeline, storage and other segment owned 113 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 at September 30, 2010:

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	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	232,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	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	60,458,299	30,549,198	91,007,497	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 at September 30, 2010:

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	16,993,683	343,746
	Louisiana Division	2,608,255	159,620
	Mississippi Division	3,875,429	165,402
	West Texas Division	2,125,000	76,000
Total		29,839,610	853,000
Natural Gas Marketing Segment	Atmos Energy Marketing, LLC	8,026,869	250,937
Pipeline, Storage and Other Segment	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total Contracted Storage Capacity		39,540,479	1,171,444

(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. The headquarters for our nonregulated operations are in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. *Legal Proceedings.*

See Note 12 to the consolidated financial statements.

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

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2010.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2010, 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	63	13	Chairman and Chief Executive Officer
Kim R. Cocklin	59	4	President and Chief Operating Officer
Louis P. Gregory	55	10	Senior Vice President and General Counsel
Michael E. Haefner	50	2	Senior Vice President, Human Resources
Fred E. Meisenheimer	66	10	Senior Vice President, Chief Financial Officer and Treasurer

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer. On October 1, 2010, Mr. Best was named Executive Chairman of the Board.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was also appointed to the Board of Directors on November 10, 2009.

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

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

Fred E. Meisenheimer was named Senior Vice President and Chief Financial Officer in February 2009 and Treasurer in November 2009. Mr. Meisenheimer previously served the Company as Vice President and Controller from July 2000 through May 2009 and also served as interim Chief Financial Officer in January 2009.

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 2010 and 2009 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:

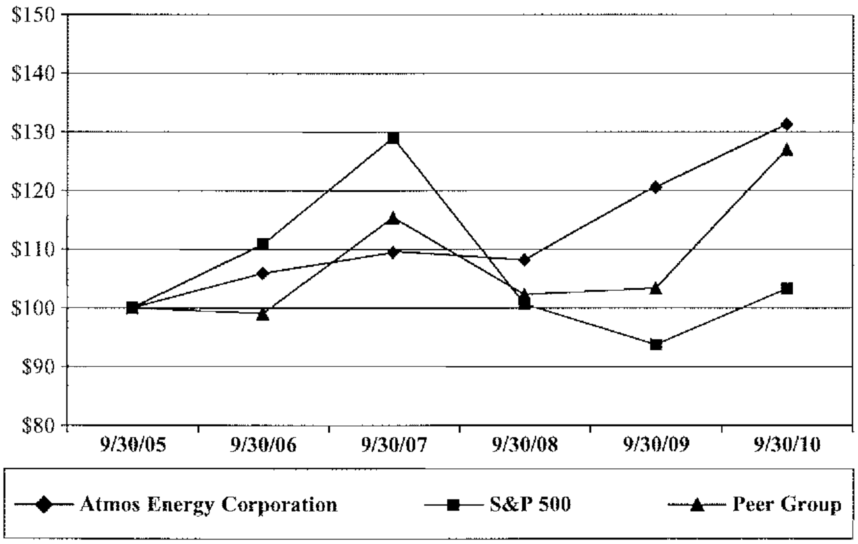
	2010			2009		
	High	Low	Dividends paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$30.06	$27.39	$.335	$27.88	$21.17	$.330
March 31	29.52	26.52	.335	25.95	20.20	.330
June 30	29.98	26.41	.335	26.37	22.81	.330
September 30	29.81	26.82	.335	28.80	24.65	.330
			$1.34			$1.32

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2010 was 19,772. 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 2010 that were not registered under the Securities Act of 1933, as amended.

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 natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2005 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 Indices



	Cumulative Total Return					
	9/30/05	9/30/06	9/30/07	9/30/08	9/30/09	9/30/10
Atmos Energy Corporation	100.00	105.89	109.44	107.92	120.52	131.27
S&P 500	100.00	110.79	129.01	100.66	93.70	103.22
Peer Group	100.00	99.04	115.40	102.25	103.34	126.98

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, EQT Corporation, Integrys Energy Group, Inc., National Fuel Gas, Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Vectren Corporation and WGL Holdings, Inc.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2010.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan . .	434,962	$22.46	848,730
Total equity compensation plans approved by security holders. . .	434,962	22.46	848,730
Equity compensation plans not approved by security holders. . .	—	—	—
Total	434,962	$22.46	848,730

ITEM 6. ***Selected Financial Data.***

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

	Fiscal Year Ended September 30				
	2010	2009(1)	2008	2007(1)	2006 (1)
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$4,789,690	$4,969,080	$7,221,305	$5,898,431	$6,152,363
Gross profit	1,364,941	1,346,702	1,321,326	1,250,082	1,216,570
Operating expenses(1)	875,505	899,300	893,431	851,446	833,954
Operating income	489,436	447,402	427,895	398,636	382,616
Miscellaneous income (expense)	(339)	(3,303)	2,731	9,184	881
Interest charges	154,471	152,830	137,922	145,236	146,607
Income before income taxes	334,626	291,269	292,704	262,584	236,890
Income tax expense	128,787	100,291	112,373	94,092	89,153
Net income	$ 205,839	$ 190,978	$ 180,331	$ 168,492	$ 147,737
Weighted average diluted shares outstanding	92,422	91,620	89,941	87,486	81,173
Diluted net income per share	$ 2.20	$ 2.07	$ 1.99	$ 1.91	$ 1.81
Cash flows from operations	$ 726,476	$ 919,233	$ 370,933	$ 547,095	$ 311,449
Cash dividends paid per share	$ 1.34	$ 1.32	$ 1.30	$ 1.28	$ 1.26
Total natural gas distribution throughput (MMcf)(2)	454,175	408,885	429,354	427,869	393,995
Total regulated transmission and storage transportation volumes (MMcf)(2)	428,599	528,689	595,542	505,493	410,505
Total natural gas marketing sales volumes (MMcf)(2)	353,853	370,569	389,392	370,668	283,962
Financial Condition					
Net property, plant and equipment	$4,793,075	$4,439,103	$4,136,859	$3,836,836	$3,629,156
Working capital	(290,887)	91,519	78,017	149,217	(1,616)
Total assets	6,763,791	6,367,083	6,386,699	5,895,197	5,719,547
Short-term debt, inclusive of current maturities of long-term debt	486,231	72,681	351,327	154,430	385,602
Capitalization:					
Shareholders' equity	2,178,348	2,176,761	2,052,492	1,965,754	1,648,098
Long-term debt (excluding current maturities)	1,809,551	2,169,400	2,119,792	2,126,315	2,180,362
Total capitalization	3,987,899	4,346,161	4,172,284	4,092,069	3,828,460
Capital expenditures	542,636	509,494	472,273	392,435	425,324
Financial Ratios					
Capitalization ratio(3)	48.7%	49.3%	45.4%	46.3%	39.1%
Return on average shareholders' equity(4)	9.1%	8.9%	8.8%	8.8%	8.9%

(1) Financial results for 2009, 2007 and 2006 include a $5.4 million, $6.3 million and a $22.9 million pre-tax loss for the impairment of certain assets.

(2) Net of intersegment eliminations.

(3) 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.

(4) 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.

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

INTRODUCTION

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

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

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, fair value measurements, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee quarterly. Actual results may differ from estimates.

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We meet the criteria established within accounting principles generally accepted in the United States of a cost-based, rate-regulated entity, which requires us to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements in accordance with applicable authoritative accounting standards. We apply the provisions of this standard to our regulated operations and record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities 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 it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities 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 regulated operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

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

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities, which are subject to refund. 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 cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of cost, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility company's other costs, (ii) represents a large component of the utility company's cost of service and (iii) is generally outside the control of the gas utility company. There is no gross profit generated through purchased gas cost 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 cost adjustment mechanism. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

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

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments.

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

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

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk in this segment are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

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

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

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

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

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt with Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements are executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement was initially recorded as a component of accumulated other comprehensive income (loss) and is recognized as a component of interest expense over the life of the related financing arrangement.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. As of September 30, 2010, we had no indefinite-lived intangible assets.

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

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

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

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Prior to fiscal 2009, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. Effective October 1, 2008, we changed our measurement date to September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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

Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $1.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.9 million.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

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

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 61 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

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

During the current year, colder-than-normal weather and recent improvements in rate designs in our natural gas distribution segment partially offset the decline in demand for natural gas, which contributed to a 19 percent year-over-year decrease in consolidated throughput in our regulated transmission and storage segment and a 5 percent year-over-year decrease in consolidated sales volumes in our natural gas marketing segment.

During the year, we continued to successfully access the capital markets and received updated debt ratings from three rating agencies. In December 2009 we renewed a $450 million 364-day committed credit facility for our nonregulated operations. In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the existing credit rating on our senior long-term debt and commercial paper while S&P affirmed our rating outlook as stable and our senior long-term debt credit rating. In June 2010, Fitch upgraded our rating outlook from stable to positive and affirmed the existing credit rating on our senior unsecured debt and commercial paper. In October 2010, we replaced our $200 million 364-day revolving credit agreement prior to its expiration with a $200 million 180-day revolving credit agreement. The new credit facilities should help ensure we have sufficient liquidity to fund our working capital needs, while our credit ratings should help us continue to obtain financing at a reasonable cost in the future.

On July 1, 2010, we entered into an accelerated share repurchase program with Goldman Sachs & Co. as part of our ongoing efforts to improve shareholder value. The shares that will be repurchased under this program should offset the dilutive impact of stock grants made under our various employee and director incentive compensation plans. The impact of the shares repurchased under the program during fiscal 2010 increased diluted earnings per share by approximately $0.01.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2010, 2009 and 2008.

	For the Fiscal Year Ended September 30		
	2010	2009	2008
	(In thousands, except per share data)		
Operating revenues	$4,789,690	$4,969,080	$7,221,305
Gross profit	1,364,941	1,346,702	1,321,326
Operating expenses	875,505	899,300	893,431
Operating income	489,436	447,402	427,895
Miscellaneous income (expense)	(339)	(3,303)	2,731
Interest charges	154,471	152,830	137,922
Income before income taxes	334,626	291,269	292,704
Income tax expense	128,787	100,291	112,373
Net income	$ 205,839	$ 190,978	$ 180,331
Earnings per diluted share	$ 2.20	$ 2.07	$ 1.99

Historically, our regulated operations arising from our natural gas distribution and regulated transmission and storage operations contributed 65 to 85 percent of our consolidated net income. Regulated operations contributed 81 percent, 83 percent and 74 percent to our consolidated net income for fiscal years 2010, 2009, and 2008. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2010	2009	2008
	(In thousands)		
Natural gas distribution segment	$125,949	$116,807	$ 92,648
Regulated transmission and storage segment	41,486	41,056	41,425
Natural gas marketing segment	27,729	20,194	29,989
Pipeline, storage and other segment	10,675	12,921	16,269
Net income	$205,839	$190,978	$180,331

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

	For the Fiscal Year Ended September 30		
	2010	2009	2008
	(In thousands, except per share data)		
Regulated operations	$167,435	$157,863	$134,073
Nonregulated operations	38,404	33,115	46,258
Consolidated net income	$205,839	$190,978	$180,331
Diluted EPS from regulated operations	$ 1.79	$ 1.71	$ 1.48
Diluted EPS from nonregulated operations	0.41	0.36	0.51
Consolidated diluted EPS	$ 2.20	$ 2.07	$ 1.99

Net income during fiscal 2010 increased eight percent over fiscal 2009. Net income from our regulated operations increased six percent during fiscal 2010. The increase primarily reflects colder than normal weather in most of our service areas as well as the net favorable impact of various ratemaking activities in our natural gas distribution segment. Net income in our nonregulated operations increased $5.3 million during fiscal 2010 primarily due to the impact of unrealized margins. Non-cash, net unrealized margins totaled $4.3 million which reduced earnings per share by $0.05 per diluted share compared to the prior year, when net unrealized losses totaled $21.6 million, which reduced earnings per share by $0.23 per diluted share.

Net income in both periods was impacted by nonrecurring items. The current year period includes the positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. Net income in the prior-year period included the net positive impact of several one-time items totaling $17.1 million, or $0.19 per diluted share related to the following pre-tax amounts:

- $11.3 million related to a favorable one-time tax benefit.
- $7.6 million related to the favorable impact of an update to the estimate for unbilled accounts.
- $7.0 million favorable impact of the reversal of estimated uncollectible gas costs.
- $5.4 million unfavorable impact of a non-cash impairment charge related to available-for-sale securities in our Supplemental Executive Retirement Plan.

Net income during fiscal 2009 increased six percent over fiscal 2008, driven largely from an 18 percent increase in net income from regulated operations during fiscal 2009. The increase primarily reflects a $32.3 million increase in gross profit resulting from the net favorable impact of various ratemaking activities in our natural gas distribution segment, partially offset by higher depreciation expense, pipeline maintenance costs and interest expense. Net income in our nonregulated operations decreased $13.1 million primarily due to the impact of unrealized margins. Pre-tax unrealized margins totaled $35.9 million which reduced earnings per share by $0.23 per diluted share. The overall increase in consolidated net income was also favorably affected by non-recurring items totaling $17.1 million, or $0.19 per diluted share, related to the items noted above.

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

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, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as 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. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective which have significantly reduced the impact of this timing difference. However, this timing difference is still present for gross receipts taxes.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 65 percent of our residential and commercial margins.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2010, 2009 and 2008 are presented below.

	For the Fiscal Year Ended September 30				
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
	(In thousands, unless otherwise noted)				
Gross profit	$1,049,447	$1,024,628	$1,006,066	$24,819	$ 18,562
Operating expenses	726,993	735,614	744,901	(8,621)	(9,287)
Operating income	322,454	289,014	261,165	33,440	27,849
Miscellaneous income	1,384	5,766	9,689	(4,382)	(3,923)
Interest charges	118,430	124,055	117,933	(5,625)	6,122
Income before income taxes	205,408	170,725	152,921	34,683	17,804
Income tax expense	79,459	53,918	60,273	25,541	(6,355)
Net income	$ 125,949	$ 116,807	$ 92,648	$ 9,142	$ 24,159
Consolidated natural gas distribution sales volumes — MMcf	322,628	282,117	292,676	40,511	(10,559)
Consolidated natural gas distribution transportation volumes — MMcf	131,547	126,768	136,678	4,779	(9,910)
Total consolidated natural gas distribution throughput — MMcf	454,175	408,885	429,354	45,290	(20,469)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.47	$ 0.44	$ —	$ 0.03
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.77	$ 6.95	$ 9.05	$ (1.18)	$ (2.10)

The following table shows our operating income by natural gas distribution division for the fiscal years ended September 30, 2010, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
	(In thousands)				
Mid-Tex	$134,655	$127,625	$115,009	$ 7,030	$12,616
Kentucky/Mid-States	57,866	47,978	48,731	9,888	(753)
Louisiana	45,759	43,434	39,090	2,325	4,344
West Texas	33,509	23,338	13,843	10,171	9,495
Colorado-Kansas	25,200	21,321	20,615	3,879	706
Mississippi	26,441	21,287	19,970	5,154	1,317
Other	(976)	4,031	3,907	(5,007)	124
Total	$322,454	$289,014	$261,165	$33,440	$27,849

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $24.8 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $33.7 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana, Kentucky, Tennessee, Virginia and Mississippi service areas.

- $11.2 million increase as a result of an 11 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $7.6 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior-year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $1.6 million decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $8.6 million, primarily due to the following:

- $5.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $4.6 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in the prior year.
- $4.4 million decrease in contract labor expenses.
- $4.4 million decrease in travel, legal and other administrative costs.

These decreases were partially offset by:

- $7.4 million increase in employee-related expenses.
- $4.3 million increase in taxes, other than income.

Miscellaneous income decreased $4.4 million due to lower interest income. Interest charges decreased $5.6 million primarily due to lower short-term debt balances and interest rates.

Additionally, results for the fiscal year ended September 30, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. During the second quarter of fiscal 2009, the Company completed a study of the calculations used to estimate its deferred tax rate, and concluded that revisions to these calculations to include more specific jurisdictional tax rates would result in a more accurate calculation of the tax rate at which deferred taxes would reverse in the future. Accordingly, the Company modified the tax rate used to calculate deferred taxes from 38 percent to an individual rate for each legal entity. These rates vary from 36-41 percent depending on the jurisdiction of the legal entity.

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

The $18.6 million increase in natural gas distribution gross profit primarily reflects an increase in rates. The major components of the increase are as follows:

- $13.6 million net increase in rates in the Mid-Tex Division as a result of the implementation of its 2008 Rate Review Mechanism (RRM) filing with all incorporated cities in the division other than the City of Dallas and environs (the Settled Cities) and adjustments for customers in the City of Dallas.
- $16.0 million increase in other rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas.
- $7.6 million increase attributable to a non-recurring update to our estimate for gas delivered to customers but not yet billed to reflect changes in base rates in several of our jurisdictions recorded in the fiscal first quarter.
- $7.0 million uncollectible gas cost accrual recorded in a prior year that was reversed in the current year period.

These increases were partially offset by:

- $17.9 million decrease as a result of a five percent decrease in consolidated distribution throughput primarily associated with lower residential, commercial and industrial consumption and warmer weather in our Colorado service area, which does not have weather-normalized rates.
- $10.8 million decrease due to lower revenue related taxes, partially offset by the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income discussed below.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $9.3 million, primarily due to the following:

- $10.6 million decrease due to lower legal, fuel and other administrative costs.
- $9.2 million decrease in allowance for doubtful accounts due to the impact of recent rate design changes in certain jurisdictions that allow us to recover the gas cost portion of uncollectible accounts as well as a 23 percent year-over-year decline in the average cost of gas.
- $9.2 million decrease in taxes other than income primarily associated with lower franchise fees and state gross receipt taxes.

These decreases were partially offset by:

- $15.1 million increase in depreciation and amortization, due primarily to additional assets placed in service during the current year.
- $4.6 million increase due to a noncash charge to impair certain available-for-sale investments as we believed the fair value of these investments would not recover within a reasonable period of time.

As discussed above, the results for fiscal 2009 include a $10.5 million tax benefit in the natural gas distribution segment. In addition, results for fiscal 2008 included a $1.2 million gain on the sale of irrigation assets in our West Texas Division.

Interest charges increased $6.1 million primarily due to the effect of the Company's March 2009 issuance of $450 million 8.50% senior notes to repay $400 million 4.00% senior notes in April 2009. In addition, we experienced higher average short-term debt balances, interest rates and commitment fees during the current year compared to the prior year.

Regulated Transmission and Storage Segment

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

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the sole supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2010, 2009, and 2008 are presented below.

	For the Fiscal Year Ended September 30				
	2010	**2009**	**2008**	**2010 vs. 2009**	**2009 vs. 2008**
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$102,891	$ 89,348	$ 86,665	$ 13,543	$ 2,683
Third-party transportation	73,648	95,314	85,256	(21,666)	10,058
Storage and park and lend services	10,657	11,858	9,746	(1,201)	2,112
Other	15,817	13,138	14,250	2,679	(1,112)
Gross profit	203,013	209,658	195,917	(6,645)	13,741
Operating expenses	105,975	116,495	106,172	(10,520)	10,323
Operating income	97,038	93,163	89,745	3,875	3,418
Miscellaneous income	135	1,433	1,354	(1,298)	79
Interest charges	31,174	30,982	27,049	192	3,933
Income before income taxes	65,999	63,614	64,050	2,385	(436)
Income tax expense	24,513	22,558	22,625	1,955	(67)
Net income	$ 41,486	$ 41,056	$ 41,425	$ 430	$ (369)
Gross pipeline transportation volumes — MMcf	634,885	706,132	782,876	(71,247)	(76,744)
Consolidated pipeline transportation volumes — MMcf	428,599	528,689	595,542	(100,090)	(66,853)

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $6.6 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.3 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $2.6 million decrease due to decreased through-system volumes primarily associated with market conditions that resulted in reduced wellhead production, decreased drilling activity and increased competition, partially offset by increased deliveries to our Mid-Tex Division.
- $1.6 million net decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.

These decreases were partially offset by the following:

- $9.3 million increase associated with our GRIP filings.
- $2.0 million increase of excess inventory sales in the current-year period.

Operating expenses decreased $10.5 million primarily due to:

- $11.8 million decrease related to reduced contract labor.
- $2.0 million decrease due to a state sales tax reimbursement received in March 2010.

These decreases were partially offset by a $2.1 million increase in taxes, other than income due to higher ad valorem and payroll taxes.

Miscellaneous income decreased $1.3 million due primarily to a decline in intercompany interest income.

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

The $13.7 million increase in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.0 million increase from higher demand-based fees.
- $5.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions.
- $5.4 million increase due to our GRIP filings.

These increases were primarily offset by an $8.4 million decrease associated with a decrease in transportation volumes to our Mid-Tex Division due to warmer weather and a decrease in electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $10.3 million primarily due to higher levels of pipeline maintenance activities.

Results for the current-year period also include a $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

Natural Gas Marketing Segment

AEM's primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. In addition, AEM utilizes proprietary and customer-owned transportation and storage assets to provide various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEM's margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEM seeks to enhance its gross profit margin from delivering gas by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity we own or control in our natural gas distribution and natural gas marketing segments. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEM has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

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

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

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

Due to the nature of these operations, natural gas prices, and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our natural gas marketing operations. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

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

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the fiscal years ended September 30, 2010, 2009 and 2008 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

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

	For the Fiscal Year Ended September 30				
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
	(In thousands, unless otherwise noted)				
Realized margins					
Delivered gas	$ 59,523	$ 75,341	$ 73,627	$(15,818)	$ 1,714
Asset optimization	37,214	37,670	(6,135)	(456)	43,805
	96,737	113,011	67,492	(16,274)	45,519
Unrealized margins	(10,786)	(28,399)	25,529	17,613	(53,928)
Gross profit	85,951	84,612	93,021	1,339	(8,409)
Operating expenses	31,699	38,208	36,629	(6,509)	1,579
Operating income	54,252	46,404	56,392	7,848	(9,988)
Miscellaneous income	2,280	537	2,022	1,743	(1,485)
Interest charges	9,280	12,911	9,036	(3,631)	3,875
Income before income taxes	47,252	34,030	49,378	13,222	(15,348)
Income tax expense	19,523	13,836	19,389	5,687	(5,553)
Net income	$ 27,729	$ 20,194	$ 29,989	$ 7,535	$ (9,795)
Gross natural gas marketing sales volumes — MMcf	420,203	441,081	457,952	(20,878)	(16,871)
Consolidated natural gas marketing sales volumes — MMcf	353,853	370,569	389,392	(16,716)	(18,823)
Net physical position (Bcf)	13.7	13.8	8.0	(0.1)	5.8

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

AEM's delivered gas business contributed 62 percent of total realized margins during the fiscal year ended September 30, 2010 with asset optimization activities contributing the remaining 38 percent. The $16.3 million decrease in realized gross profit reflected the following:

- $15.8 million decrease in realized delivered gas margins due to lower per-unit margins as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit margins were $0.14/Mcf in the current-year period compared with $0.17/Mcf in the prior-year period, while delivered sales volumes were 5 percent lower in the current year when compared with the prior year.
- $0.5 million decrease in asset optimization margins primarily due to higher storage demand fees partially offset by higher realized storage and trading gains during the fiscal year.

The decrease in realized gross profit was more than offset by a $17.6 million increase in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes and asset impairments decreased $6.5 million primarily due to a decrease in employee and other administrative costs.

Miscellaneous income increased $1.7 million due to proceeds received from a class-action legal settlement in the current year. Interest charges decreased $3.6 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEM's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEM's economic value and its potential gross profit (loss) at September 30, 2010 and 2009.

	September 30	
	2010	2009
	(In millions, unless otherwise noted)	
Economic value	$(7.8)	$ 28.6
Associated unrealized losses	12.6	11.0
Subtotal	4.8	39.6
Related fees[1]	(9.6)	(14.7)
Potential gross profit (loss)	$(4.8)	$ 24.9
Net physical position (Bcf)	13.7	13.8

[1] Related fees represent AEM's contractual costs to acquire the storage capacity utilized in its asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index in exchange for the right to manage and optimize third party storage assets for the positions AEM has entered into as of September 30, 2010 and 2009.

During the fiscal year ended September 30, 2010, AEM's economic value decreased from $28.6 million, or $2.07/Mcf at September 30, 2009 to a negative economic value of $7.8 million, or $0.57/Mcf.

Early in the first quarter of fiscal 2010, AEM withdrew gas and realized previously captured spread values. As current cash prices declined during the first fiscal quarter, AEM injected gas and rolled positions into the second fiscal quarter to increase economic value. These positions were settled in the second fiscal quarter and the associated economic value was realized. However, during the year, weak market fundamentals have caused cash prices to remain low and have contracted spot-to-forward spread values, which has limited opportunities to capture economic value. Therefore, during the fiscal third and fourth quarters, AEM elected to forego capturing these narrower spread values and maintained a short-term trading position. We anticipate spot-to-forward spread values will expand in the near term and we expect to be able to roll positions and capture greater economic value than what we can capture as of September 30, 2010. However, the short-dated nature of AEM's trading positions combined with current short-term forward prices that are lower than the cost of gas that was injected into storage in prior periods resulted in negative economic value as of September 30, 2010.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit or loss calculated as of September 30, 2010 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

AEM's delivered gas business contributed 67 percent to total realized margins during fiscal 2009 with asset optimization activities contributing the remaining 33 percent. In the prior year, delivered gas activities represented substantially all of AEM's realized gross profit margin. The $45.5 million increase in realized gross profit reflected:

- A $43.8 million increase in asset optimization margins. AEM realized substantially all of its realized asset optimization margin in the fiscal 2009 first quarter when it realized substantially all of the economic value that it had captured as of September 30, 2008 from withdrawing gas and settling the associated financial instruments. Since that time, as a result of falling current cash prices, AEM has been deferring storage withdrawals and has been a net injector of gas into storage to increase the economic value it could realize in future periods from its asset optimization activities. In the prior year, AEM deferred storage withdrawals primarily into fiscal 2009 and recognized losses on the settlement of the associated financial instruments.
- A $1.7 million increase in realized delivered gas margins. AEM experienced a six percent increase in per-unit margins as a result of improved basis spreads in certain market areas where we were able to better optimize transportation assets and successful contract renewals. These margins improvements more than offset a four percent decrease in gross sales volumes primarily attributable to lower industrial demand as a result of the current economic climate.

The increase in realized gross profit was more than offset by a $53.9 million decrease in unrealized margins attributable to the following:

- The realization of unrealized gains recorded during fiscal 2008.
- A modest widening of the physical/financial spreads, partially offset by favorable unrealized basis gains in certain markets.
- A 5.8 Bcf increase in AEM's net physical position.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments increased $1.6 million primarily due the following factors:

- $4.0 million increase in legal and other administrative costs.
- $2.4 million decrease related to tax matters incurred in the prior year that did not recur in the current year.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS is engaged in nonregulated transmission, storage and natural gas-gathering services. Its primary asset is a proprietary 21 mile pipeline located in New Orleans, Louisiana that is principally used to aggregate gas supply for our regulated natural gas distribution division in Louisiana, our natural gas marketing segment, and, on a more limited basis, for third parties. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for additional pipeline capacity to meet customer demand during peak periods.

In addition, APS engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements. APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls by engaging in natural gas storage transactions in which it seeks to find and profit from the pricing differences that occur over time.

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

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the fiscal years ended September 30, 2010, 2009 and 2008 are presented below.

	For the Fiscal Year Ended September 30				
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
			(In thousands)		
Storage and transportation services	$13,206	$12,784	$14,247	$ 422	$ (1,463)
Asset optimization	10,286	21,474	5,178	(11,188)	16,296
Other	1,652	2,728	4,183	(1,076)	(1,455)
Unrealized margins	2,996	(7,490)	4,705	10,486	(12,195)
Gross profit	28,140	29,496	28,313	(1,356)	1,183
Operating expenses	12,448	11,019	8,064	1,429	2,955
Operating income	15,692	18,477	20,249	(2,785)	(1,772)
Miscellaneous income	3,083	6,253	8,428	(3,170)	(2,175)
Interest charges	2,808	1,830	2,322	978	(492)
Income before income taxes	15,967	22,900	26,355	(6,933)	(3,455)
Income tax expense	5,292	9,979	10,086	(4,687)	(107)
Net income	$10,675	$12,921	$16,269	$ (2,246)	$ (3,348)

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

Gross profit from our pipeline, storage and other segment decreased $1.4 million primarily due to the following:

- $4.9 million decrease from lower margins earned on storage optimization activities.
- $3.9 million decrease in basis gains earned from utilizing leased capacity.
- $2.4 million decrease from lower margins earned on asset management plans.
- $10.5 million increase in unrealized margins associated with our asset optimization activities.

Operating expenses increased $1.4 million primarily due to increased operating costs associated with APS' gas gathering activities and administrative costs.

Miscellaneous income decreased $3.2 million primarily due to lower intercompany interest income earned by this segment.

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

Gross profit from our pipeline, storage and other segment increased $1.2 million primarily due to the following:

- $16.3 million increase in asset optimization margins as a result of larger realized gains from the settlement of financial positions associated with storage and trading activities, basis gains earned from utilizing controlled pipeline capacity and higher margins earned under asset management plans.
- $12.2 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses increased $3.0 million primarily due to increased employee costs and higher depreciation expense which was largely attributable to additional assets placed in service during the year.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. In fiscal 2011, we anticipate consolidating our short-term facilities used for our regulated operations into a single line of credit. In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement. Additionally, we intend to replace AEM's $450 million 364-day facility with a $200 million, three-year facility when it expires in December 2010.

Our $350 million unsecured 7.375% Senior Notes will mature in May 2011. We intend to refinance this debt on a long-term basis through the issuance of 30-year unsecured senior notes in June 2011. Additionally, we plan to issue $250 million of 30-year unsecured senior notes in November 2011 to fund our capital expenditure program. On September 30, 2010, we entered into five Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. We designated all of the Treasury lock agreements as cash flow hedges of an anticipated transaction. Any realized gain or loss incurred when these agreements are settled will be recognized as a component of interest expense over the life of the related long-term debt.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2011.

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 such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2010, 2009 and 2008 are presented below.

	For the Fiscal Year Ended September 30				
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 726,476	$ 919,233	$ 370,933	$(192,757)	$ 548,300
Investing activities	(542,702)	(517,201)	(483,009)	(25,501)	(34,192)
Financing activities	(163,025)	(337,546)	98,068	174,521	(435,614)
Change in cash and cash equivalents	20,749	64,486	(14,008)	(43,737)	78,494
Cash and cash equivalents at beginning of period	111,203	46,717	60,725	64,486	(14,008)
Cash and cash equivalents at end of period	$ 131,952	$ 111,203	$ 46,717	$ 20,749	$ 64,486

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Fiscal Year ended September 30, 2010 compared with fiscal year ended September 30, 2009

For the fiscal year ended September 30, 2010, we generated operating cash flow of $726.5 million from operating activities compared with $919.2 million in the prior year, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flows for the fiscal 2010 period reflect the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flows were favorably influenced by the recovery of high gas costs during a period of falling prices.

Fiscal Year ended September 30, 2009 compared with fiscal year ended September 30, 2008

Operating cash flows were $548.3 million higher in fiscal 2009 compared to fiscal 2008, primarily due to the following:

- $368.9 million increase attributable to the favorable impact on our working capital due to the decline in natural gas prices in the current year compared to the prior year.
- $56.8 million increase due to lower cash margin requirements related to our natural gas marketing financial instruments.
- These increases were partially offset by a $21.0 million decrease due to a contribution made to our pension plans in the current year.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund acquisitions and growth projects, our ongoing construction program and improvements to information technology 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 focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. 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.

Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. Two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program will commence in fiscal 2011 at a total projected capital cost of $80 — $120 million, with completion expected in September 2012. As a result of this project and spending to replace our regulated customer service systems and our nonregulated energy trading risk management system, we anticipate capital expenditures will increase significantly during the next two fiscal years.

For the fiscal year ended September 30, 2010, we incurred $542.6 million for capital expenditures compared with $509.5 million for the fiscal year ended September 30, 2009 and $472.3 million for the fiscal year ended September 30, 2008.

The $33.1 million increase in capital expenditures in fiscal 2010 compared to fiscal 2009 primarily reflects spending for the relocation of our information technology data center to a new facility, the construction of two service centers and the steel service line replacement program in our Mid-Tex Division.

The increase in capital expenditures in fiscal 2009 compared to fiscal 2008 primarily reflects $32.6 million related to spending for a regulated transmission pipeline project completed in the fourth quarter of 2009.

Cash flows from financing activities

For the fiscal year ended September 30, 2010, our financing activities used $163.0 million in cash, while financing activities for the fiscal year ended September 30, 2009 used $337.5 million in cash compared with cash of $98.1 million provided for the fiscal year ended September 30, 2008. Our significant financing activities for the fiscal years ended September 30, 2010, 2009 and 2008 are summarized as follows:

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under our accelerated share repurchase program.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that in fiscal 2010 shares have begun to be purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

2009

During the fiscal year ended September 30, 2009, we:

- Paid $407.4 million to repay our $400 million 4.00% unsecured notes.
- Repaid a net $284.0 million short-term borrowings under our credit facilities.

- Paid $121.5 million in cash dividends which reflected a payout ratio of 64 percent of net income.
- Received $445.6 million in net proceeds related to the March 2009 issuance of $450 million of 8.50% Senior Notes due 2019. The net proceeds were used to repay the $400 million 4.00% unsecured notes.
- Received $27.7 million net proceeds related to the issuance of 1.2 million shares of common stock.
- Received $1.9 million net proceeds related to the settlement of the Treasury lock agreement associated with the March 2009 issuance of the $450 million of 8.50% Senior Notes due 2019.

2008

During the fiscal year ended September 30, 2008, we:

- Borrowed a net $200.2 million under our short-term facilities due to the impact of seasonal natural gas purchases and the effect of higher natural gas prices.
- Repaid $10.3 million long-term debt in accordance with their normal maturity schedules.
- Received $25.5 million in net proceeds related to the issuance of 1.0 million shares of common stock.
- Paid $117.3 million in dividends, which reflected a payout ratio of 65 percent of net income.

The following table shows the number of shares issued for the fiscal years ended September 30, 2010, 2009 and 2008:

	For the Fiscal Year Ended September 30		
	2010	**2009**	**2008**
Shares issued:			
Direct stock purchase plan	103,529	407,262	388,485
Retirement savings plan	79,722	640,639	558,014
1998 Long-term incentive plan	421,706	686,046	538,450
Outside directors stock-for-fee plan	3,382	3,079	3,197
Total shares issued	608,339	1,737,026	1,488,146

The year-over-year decrease in the number of shares issued primarily reflects the fact that in fiscal 2010, shares have begun to be purchased in the open market rather than by being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan. In addition, we awarded fewer shares under our 1998 Long-Term Incentive Plan due to the Company achieving a lower level of performance relative to the target performance established under the Plan during fiscal 2009 compared to fiscal 2008. Further, a higher average stock price during the second and third quarters of fiscal 2010 compared to the second and third quarters of 2009 enabled us to issue fewer shares during the current year.

During the fiscal year, we repurchased 2,958,580 common shares as part of the accelerated share repurchase agreement that is described in further detail below. Additionally, we repurchased 37,365 shares attributable to equity awards during the year. The repurchased share activity is not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. We will receive the balance of the shares at the conclusion of the term of the repurchase agreement. The specific number of shares we will ultimately repurchase in the transaction will be based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. The agreement is scheduled to end in

March 2011, although the termination date may be accelerated at the option of Goldman Sachs & Co. As a result of this transaction, beginning in our fourth fiscal quarter, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity. The number of shares used to calculate our earnings per share in fiscal 2011 will continue to be reduced by the shares we received in July 2010; however, the total impact to diluted earnings per share for fiscal 2011 will be dependent upon the average share price of our common stock over the remainder of the agreement.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings typically reach their highest levels in the winter months.

As of September 30, 2010, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. As of September 30, 2010, the amount available to us under our credit facilities, net of outstanding letters of credit was $834.8 million. These facilities are described in further detail in Note 6 to the consolidated financial statements.

In October 2010, our $200 million 364-day facility expired and our five-year $566.7 million facility will expire in December 2011. We replaced the $200 million 364-day facility before its expiration with a $200 million 180-day credit facility that will expire in April 2011. We do not plan to replace this facility upon expiration. We expect to begin discussions in fiscal 2011 to replace the expiring five-year $566.7 million facility with a larger multi-year credit facility. We believe our existing five-year facility will provide adequate short-term borrowing capacity until we can successfully execute a new multi-year credit facility.

Additionally, on December 9, 2010, AEM's existing $450 million committed revolving credit facility will expire. In October 2010, we received regulatory approval to increase AEH's intercompany demand credit facility with AEC from $200 million to $350 million, effective December 1, 2010 through December 31, 2011. As a result of this increase, we are in discussions with our third-party lenders to replace AEM's $450 million committed revolving credit facility with a $200 million three-year committed revolving credit facility with an accordion feature that could increase AEM's borrowing capacity to $500 million. As a result of consolidating and reducing the amounts available under our facilities, we expect to reduce our short-term financing costs.

Shelf Registration

On March 31, 2010, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance. We had already received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

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 Service (Moody's) and Fitch Ratings, Ltd. (Fitch). In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the credit rating on our senior long-term debt at Baa2 and on our commercial paper at P-2. Moody's stated that the key driver for the upgrade was successful rate case outcomes over the past year. In March 2010, S&P affirmed our senior long-term debt credit rating of BBB+ and our rating outlook as stable. In June 2010, Fitch reaffirmed our senior long-term debt rating of BBB+ and commercial paper ratings of F-2 and upgraded our rating outlook from stable to positive. Fitch cited our effective management of the regulatory process as well as our consistent financial and operational performance as the primary reasons for the upgrade. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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, 2010. Our debt covenants are described in Note 6 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2010 and 2009:

	September 30			
	2010		2009	
	(In thousands, except percentages)			
Short-term debt	$ 126,100	2.8%	$ 72,550	1.6%
Long-term debt	2,169,682	48.5%	2,169,531	49.1%
Shareholders' equity	2,178,348	48.7%	2,176,761	49.3%
Total capitalization, including short-term debt	$4,474,130	100.0%	$4,418,842	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.3 percent and 50.7 percent at September 30, 2010 and 2009. The increase in the debt to capitalization ratio primarily reflects an increase in short-term debt as of September 30, 2010 compared to the prior year. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2010.

	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)	$2,172,696	$360,131	$252,565	$500,000	$1,060,000
Short-term debt(1)	126,100	126,100	—	—	—
Interest charges(2)	1,040,151	130,826	219,726	179,347	510,252
Gas purchase commitments(3)	346,186	264,525	79,758	1,903	—
Capital lease obligations(4)	1,380	186	372	372	450
Operating leases(4)	217,184	18,240	33,407	31,207	134,330
Demand fees for contracted storage(5)	26,305	13,332	10,243	2,730	—
Demand fees for contracted transportation(6)	32,422	8,678	15,744	7,759	241
Financial instrument obligations(7)	58,597	49,673	8,924	—	—
Postretirement benefit plan contributions(8)	154,511	13,006	24,584	29,882	87,039
Uncertain tax positions (including interest)(9)	6,731	—	6,731	—	—
Total contractual obligations	$4,182,263	$984,697	$652,054	$753,200	$1,792,312

(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, 2010.

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

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

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

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2010. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.

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

(9) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2010, AEM was committed to purchase 69.5 Bcf within one year, 28.4 Bcf within one to three years and 3.2 Bcf after three years under indexed contracts. AEM is committed to purchase 3.1 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.55 to $6.36 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 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, 2010 are reflected in the table above.

Risk Management Activities

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

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

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2010 (in thousands):

Fair value of contracts at September 30, 2009	$(14,166)
Contracts realized/settled	(34,575)
Fair value of new contracts	(6,764)
Other changes in value	5,905
Fair value of contracts at September 30, 2010	$(49,600)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2010, is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at September 30, 2010 — Maturity in Years — Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(46,723)	$(2,877)	$—	$—	$(49,600)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(46,723)	$(2,877)	$—	$—	$(49,600)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the fiscal year ended September 30, 2010 (in thousands):

Fair value of contracts at September 30, 2009	$ 26,698
Contracts realized/settled	(34,170)
Fair value of new contracts	—
Other changes in value	(4,902)
Fair value of contracts at September 30, 2010	(12,374)
Netting of cash collateral	24,889
Cash collateral and fair value of contracts at September 30, 2010	$ 12,515

The fair value of our natural gas marketing segment's financial instruments at September 30, 2010, is presented below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at September 30, 2010 — Maturity in Years — Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(7,264)	$(5,096)	$(14)	$—	$(12,374)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(7,264)	$(5,096)	$(14)	$—	$(12,374)

Employee Benefit Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefit programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2005, we have experienced medical and prescription inflation of approximately seven percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2010, our total net periodic pension and other benefits costs was $50.8 million, compared with $50.2 million and $47.9 million for the fiscal years ended September 30, 2009 and 2008. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

The increase in total net periodic pension and other benefits costs during fiscal 2010 compared with fiscal 2009 primarily reflects the decline in fair value of our plan assets. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2009 measurement date, the interest rates were slightly lower than the interest rates at September 30, 2008, the measurement date used to determine our fiscal 2009 net periodic cost. Our expected return on our pension plan assets remained constant at 8.25%.

The increase in total net periodic pension and other benefits costs during fiscal 2009 compared with fiscal 2008 primarily reflects the change in assumptions we made during our annual pension plan valuation completed September 30, 2008. The discount rate used to compute the present value of a plan's liabilities generally was based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2008 measurement date, the interest rates were approximately 130 basis points higher than the interest rates at June 30, 2007, the measurement date used to determine our fiscal 2008 net periodic cost. The corresponding increase in the discount rate was the primary driver for the increase in our fiscal 2009 pension and benefit costs. Our expected return on our pension plan assets remained constant at 8.25%.

Pension and Postretirement Plan Funding

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

During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the Pension Protection Act of 2006 (PPA). During fiscal 2009, we contributed $21.0 million to our pension plans to achieve the same desired level of funding as established by the PPA. During fiscal 2008, we voluntarily contributed $2.3 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. This contribution achieved a desired level of funding for this plan for the 2007 plan year.

We contributed $11.8 million, $10.1 million and $9.6 million to our postretirement benefits plans for the fiscal years ended September 30, 2010, 2009 and 2008. 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 2011 and Beyond

As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2011 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent uncertainty in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is partially mitigated by the fact that assets are smoothed for purposes of determining net periodic pension cost which results in asset gains and losses that are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Due to the decline in the fair value of our plan assets, we expect our fiscal 2011 pension and postretirement medical costs to increase compared to fiscal 2010. Based upon market conditions subsequent to September 30, 2010, the current funded position of the plans and the new funding requirements under the PPA, we believe it is reasonably possible that we will be required to contribute to the Plans in fiscal 2011. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions. With respect to our postretirement medical plans, we anticipate contributing approximately $13.0 million during fiscal 2011.

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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 will be allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who choose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. Although we are still assessing the impact of the Health Care Reform Act on the health care benefits we provide to our employees, the design of our health care plans has already changed in order to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in 2011. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2011, we anticipate an approximate 10 percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the initial implementation of the Health Care Reform Act.

RECENT ACCOUNTING DEVELOPMENTS

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

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

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

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

Commodity Price Risk

Natural gas distribution segment

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

Natural gas marketing and pipeline, storage and other segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a \$0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2010 of 0.1 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, 2010 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 \$4.8 million.

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

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term 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 \$1.5 million during 2010.

As of September 30, 2010, 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.

ITEM 8. *Financial Statements and Supplementary Data.*

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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 and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2010 and 2009, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2010, 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, 2010, 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 12, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2010

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30	
	2010	2009
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,384,396	$5,981,420
Construction in progress	157,922	105,198
	6,542,318	6,086,618
Less accumulated depreciation and amortization	1,749,243	1,647,515
Net property, plant and equipment	4,793,075	4,439,103
Current assets		
Cash and cash equivalents	131,952	111,203
Accounts receivable, less allowance for doubtful accounts of $12,701 in 2010 and $11,478 in 2009	273,207	232,806
Gas stored underground	319,038	352,728
Other current assets	150,995	132,203
Total current assets	875,192	828,940
Goodwill and intangible assets	740,148	740,064
Deferred charges and other assets	355,376	358,976
	$6,763,791	$6,367,083
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2010 — 90,164,103 shares, 2009 — 92,551,709 shares	$ 451	$ 463
Additional paid-in capital	1,714,364	1,791,129
Accumulated other comprehensive loss	(23,372)	(20,184)
Retained earnings	486,905	405,353
Shareholders' equity	2,178,348	2,176,761
Long-term debt	1,809,551	2,169,400
Total capitalization	3,987,899	4,346,161
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	266,208	207,421
Other current liabilities	413,640	457,319
Short-term debt	126,100	72,550
Current maturities of long-term debt	360,131	131
Total current liabilities	1,166,079	737,421
Deferred income taxes	829,128	570,940
Regulatory cost of removal obligation	350,521	344,403
Deferred credits and other liabilities	430,164	368,158
	$6,763,791	$6,367,083

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2010	2009	2008
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,912,493	$2,984,765	$3,655,130
Regulated transmission and storage segment	203,013	209,658	195,917
Natural gas marketing segment	2,151,264	2,336,847	4,287,862
Pipeline, storage and other segment	35,318	41,924	31,709
Intersegment eliminations	(512,398)	(604,114)	(949,313)
	4,789,690	4,969,080	7,221,305
Purchased gas cost			
Natural gas distribution segment	1,863,046	1,960,137	2,649,064
Regulated transmission and storage segment	—	—	—
Natural gas marketing segment	2,065,313	2,252,235	4,194,841
Pipeline, storage and other segment	7,178	12,428	3,396
Intersegment eliminations	(510,788)	(602,422)	(947,322)
	3,424,749	3,622,378	5,899,979
Gross profit	1,364,941	1,346,702	1,321,326
Operating expenses			
Operation and maintenance	468,038	494,010	500,234
Depreciation and amortization	216,960	217,208	200,442
Taxes, other than income	190,507	182,700	192,755
Asset impairments	—	5,382	—
Total operating expenses	875,505	899,300	893,431
Operating income	489,436	447,402	427,895
Miscellaneous income (expense), net	(339)	(3,303)	2,731
Interest charges	154,471	152,830	137,922
Income before income taxes	334,626	291,269	292,704
Income tax expense	128,787	100,291	112,373
Net income	$ 205,839	$ 190,978	$ 180,331
Per share data			
Basic net income per share	$ 2.22	$ 2.08	$ 2.00
Diluted net income per share	$ 2.20	$ 2.07	$ 1.99
Weighted average shares outstanding:			
Basic	91,852	91,117	89,385
Diluted	92,422	91,620	89,941

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Additional	Accumulated Other		
	Number of Shares	Stated Value	Paid-in Capital	Comprehensive Loss	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2007	89,326,537	$447	$1,700,378	$(16,198)	$ 281,127	$1,965,754
Comprehensive income:						
Net income	—	—	—	—	180,331	180,331
Unrealized holding losses on investments, net	—	—	—	(1,897)	—	(1,897)
Treasury lock agreements, net	—	—	—	3,148	—	3,148
Cash flow hedges, net	—	—	—	(21,000)	—	(21,000)
Total comprehensive income						160,582
Retroactive charge to record initial uncertain tax positions	—	—	—	—	(569)	(569)
Cash dividends ($1.30 per share)	—	—	—	—	(117,288)	(117,288)
Common stock issued:						
Direct stock purchase plan	388,485	2	10,333	—	—	10,335
Retirement savings plan	558,014	3	15,116	—	—	15,119
1998 Long-term incentive plan	538,450	2	5,592	—	—	5,594
Employee stock-based compensation	—	—	12,878	—	—	12,878
Outside directors stock-for-fee plan	3,197	—	87	—	—	87
Balance, September 30, 2008	90,814,683	454	1,744,384	(35,947)	343,601	2,052,492
Comprehensive income:						
Net income	—	—	—	—	190,978	190,978
Unrealized holding losses on investments, net	—	—	—	(1,820)	—	(1,820)
Other than temporary impairment of investments, net	—	—	—	3,370	—	3,370
Treasury lock agreements, net	—	—	—	3,606	—	3,606
Cash flow hedges, net	—	—	—	10,607	—	10,607
Total comprehensive income						206,741
Change in measurement date for employee benefit plans	—	—	—	—	(7,766)	(7,766)
Cash dividends ($1.32 per share)	—	—	—	—	(121,460)	(121,460)
Common stock issued:						
Direct stock purchase plan	407,262	2	8,743	—	—	8,745
Retirement savings plan	640,639	3	16,571	—	—	16,574
1998 Long-term incentive plan	686,046	4	8,075	—	—	8,079
Employee stock-based compensation	—	—	13,280	—	—	13,280
Outside directors stock-for-fee plan	3,079	—	76	—	—	76
Balance, September 30, 2009	92,551,709	463	1,791,129	(20,184)	405,353	2,176,761
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net	—	—	—	1,745	—	1,745
Treasury lock agreements, net	—	—	—	2,030	—	2,030
Cash flow hedges, net	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	$451	$1,714,364	$(23,372)	$ 486,905	$2,178,348

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2010	2009	2008
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 205,839	$ 190,978	$ 180,331
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	—	5,382	—
Depreciation and amortization:			
Charged to depreciation and amortization	216,960	217,208	200,442
Charged to other accounts	173	94	147
Deferred income taxes	196,731	129,759	97,940
Stock-based compensation	12,655	14,494	14,032
Debt financing costs	11,908	10,364	10,665
Other	(1,245)	(1,177)	(5,492)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(40,401)	244,713	(97,018)
(Increase) decrease in gas stored underground	54,014	194,287	(54,726)
(Increase) decrease in other current assets	(18,387)	117,737	(120,882)
(Increase) decrease in deferred charges and other assets	14,886	(106,231)	22,476
Increase (decrease) in accounts payable and accrued liabilities	58,069	(181,978)	39,902
Increase (decrease) in other current liabilities	(48,992)	(717)	60,026
Increase in deferred credits and other liabilities	64,266	84,320	23,090
Net cash provided by operating activities	726,476	919,233	370,933
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(542,636)	(509,494)	(472,273)
Other, net	(66)	(7,707)	(10,736)
Net cash used in investing activities	(542,702)	(517,201)	(483,009)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	54,268	(283,981)	200,174
Net proceeds from issuance of long-term debt	—	445,623	—
Settlement of Treasury lock agreement	—	1,938	—
Repayment of long-term debt	(131)	(407,353)	(10,284)
Cash dividends paid	(124,287)	(121,460)	(117,288)
Repurchase of common stock	(100,450)	—	—
Repurchase of equity awards	(1,191)	—	—
Issuance of common stock	8,766	27,687	25,466
Net cash provided by (used in) financing activities	(163,025)	(337,546)	98,068
Net increase (decrease) in cash and cash equivalents	20,749	64,486	(14,008)
Cash and cash equivalents at beginning of year	111,203	46,717	60,725
Cash and cash equivalents at end of year	$ 131,952	$ 111,203	$ 46,717

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

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

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

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

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

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

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

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

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is used primarily to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

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

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods.

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.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements 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. Accounting principles generally accepted in the United States require 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.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2010 and 2009 included the following:

	September 30	
	2010	2009
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$209,564	$197,743
Merger and integration costs, net	6,714	7,161
Deferred gas costs	22,701	22,233
Regulatory cost of removal asset	31,014	23,317
Environmental costs	805	866
Rate case costs	4,505	5,923
Deferred franchise fees	1,161	10,014
Deferred income taxes, net	—	639
Other	1,046	6,218
	$277,510	$274,114
Regulatory liabilities:		
Deferred gas costs	$ 43,333	$110,754
Regulatory cost of removal obligation	381,474	358,745
Other	6,112	7,960
	$430,919	$477,459

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2010, 2009 and 2008, we recognized $0.4 million, $0.4 million and $0.4 million in amortization expense related to these costs.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. During the year ended September 30, 2009 we recognized a non-recurring $7.6 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, 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 cost adjustment mechanisms. Purchased gas cost 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 cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2010, 2009 and 2008, we included unrealized gains (losses) on open contracts of $(10.8) million, $(28.4) million and $25.5 million as a component of natural gas marketing revenues.

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

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

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

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our natural gas marketing and other nonregulated subsidiaries to conduct their operations. The average cost method is used for all our regulated operations, 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. Our natural gas marketing and pipeline, storage and other segments utilize the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $3.9 million, $4.9 million and $2.9 million was capitalized in 2010, 2009 and 2008.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.5 percent, 3.8 percent and 3.7 percent for the fiscal years ended September 30, 2010, 2009 and 2008.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 41 years.

Asset retirement obligations — 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, 2010 and 2009, we recorded asset retirement obligations of $11.4 million and $13.0 million. Additionally, we recorded $3.8 million and $3.9 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

We believe we have a legal obligation to retire our natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot 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.

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

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

Marketable securities — As of September 30, 2010 and 2009, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, 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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

Due to the deterioration of the financial markets in late calendar 2008 and early calendar 2009 and the uncertainty of a full recovery of these investments given the then current economic environment, we recorded a $5.4 million noncash charge to impair certain available-for-sale investments during fiscal 2009.

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

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

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

Financial Instruments Associated with Commodity Price Risk

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

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

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

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

In our natural gas marketing segment, we also utilize master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2010 and 2009, the Company netted $24.9 million and $11.7 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. In fiscal 2010 and in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

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

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Our Master Trust has investments in real estate that qualify as Level 3 fair value measurements. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. To comply with the new measurement date requirements established by the Financial Accounting Standards Board (FASB) and incorporated into accounting principles generally accepted in the United States, effective October 1, 2008, we changed our measurement date from June 30 to our fiscal year end, September 30. This change is more fully discussed in Note 8. The assumed discount rate 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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 will be allowed to make a one-time election to migrate from the PAP into our defined contribution plan which has been enhanced, effective January 1, 2011. Participants who choose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

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 bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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

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

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

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

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2010 and 2009, consisted of the following unrealized gains (losses):

	September 30	
	2010	2009
	(In thousands)	
Unrealized holding gains on investments	$ 4,205	$ 2,460
Treasury lock agreements	(5,468)	(7,498)
Cash flow hedges	(22,109)	(15,146)
	$(23,372)	$(20,184)

Subsequent events — We have evaluated subsequent events from the September 30, 2010 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. Except as discussed in Note 6, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — During the year ended September 30, 2010, six new accounting standards became applicable to the Company. Except as indicated below, the adoption of these standards did not have a material impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2010.

The determination of participating securities in the basic earnings per share calculation - The Financial Accounting Standards Board (FASB) issued guidance related to determining whether instruments granted in share-based payment transactions are considered participating securities. The FASB determined that non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents are participating securities and, as a result, companies with these types of participating securities must use the two-class method to compute earnings per share. Based on this guidance, the Company is required to calculate earnings per share using the two-class method and will include non-vested restricted stock and restricted stock units for which vesting is only predicated upon the passage of time in the basic earnings per share calculation. Non-vested restricted stock and restricted stock units for which vesting is predicated, in part upon the achievement of specified performance targets, continue to be excluded from the calculation of earnings per share. Although the provisions of this standard were effective for us as of October 1, 2009, prior-period earnings per share data must be recalculated and adjusted accordingly. The calculation of basic and diluted earnings per share pursuant to the two-class method is presented in Note 10. The application of the two-class method resulted in the following changes to basic and diluted earnings per share for the years ended September 30, 2009 and 2008.

	Year Ended September 30, 2009	Year Ended September 30, 2008
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Basic EPS — as previously reported	$ 2.10	$ 2.02
Basic EPS — as adjusted	$ 2.08	$ 2.00
Weighted average shares outstanding — as previously reported	91,117	89,385
Weighted average shares outstanding — as adjusted	91,117	89,385
Diluted Earnings Per Share		
Diluted EPS — as previously reported	$ 2.08	$ 2.00
Diluted EPS — as adjusted	$ 2.07	$ 1.99
Weighted average shares outstanding — as previously reported	92,024	90,272
Weighted average shares outstanding — as adjusted	91,620	89,941

Fair value measurements of plan assets of a defined benefit pension or other postretirement plan — This guidance requires employers to disclose annually information about fair value measurements of the assets of a defined benefit pension or other postretirement plan in a manner similar to the requirements established for financial and non-financial assets. The objectives of the required disclosures are to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure fair value of plan assets and significant concentrations of risk within plan assets. These disclosures appear in Note 8 for the year ended September 30, 2010.

Measurement of liabilities at fair value — This guidance requires that, effective October 1, 2009, when a quoted price in an active market for an identical liability is not available, we will be required to measure fair value using a valuation technique that uses quoted prices of similar liabilities, quoted prices of identical or similar liabilities when traded as assets, or another valuation technique that is consistent with U.S. generally accepted accounting principles (GAAP), such as the income or market approach. Additionally, when estimating the fair value of a liability, we will not be required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents our transfer of the liability. The adoption of this guidance did not impact our financial position, results of operations or cash flows.

Business combination accounting — Effective October 1, 2009, this new pronouncement established new principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. This update significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under the new guidelines, changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact current period income tax expense.

Accounting and reporting for minority interests — In December 2007, the FASB issued guidance related to the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changed the accounting for transactions with minority interest holders beginning October 1, 2009. As of September 30, 2010, Atmos Energy did not have any transactions with minority interest holders.

Fair value disclosures — The FASB issued guidance that requires new disclosures surrounding fair value measurements to enhance the existing disclosure requirements including 1) information about transfers in and out of Level 1 and Level 2 fair value measurements as well as a detailed reconciliation of activity in Level 3 fair value measurements; 2) a more detailed level of disaggregation for each class of assets and liabilities; and 3) a requirement to disclose information about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements that fall in either Level 2 or Level 3. The new disclosures and clarifications of existing disclosures became effective for us on January 1, 2010, except for the disclosures related to the detailed reconciliation of Level 3 fair value measurements, which will become effective for us on October 1, 2011. As a result of adopting this standard, beginning in our second fiscal quarter we added a disclosure about the valuation techniques and inputs we used to measure fair value for our Level 2 recurring and nonrecurring fair value measurements, which is included in Note 5. As of September 30, 2010, we did not have any Level 3 fair value measurements. Our Master Trust holds an investment in real estate which is classified as a Level 3 fair value measurement at September 30, 2010.

3. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2010 and 2009:

	September 30	
	2010	2009
	(In thousands)	
Goodwill	$739,314	$738,603
Intangible assets	834	1,461
Total	$740,148	$740,064

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2010:

	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, 2009	$571,592	$132,300	$24,282	$10,429	$738,603
Deferred tax adjustments on prior acquisitions[1]	670	41	—	—	711
Balance as of September 30, 2010	$572,262	$132,341	$24,282	$10,429	$739,314

(1) During the preparation of the fiscal 2010 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $0.7 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2010 and 2009, we had no intangible assets with indefinite lives.

		September 30, 2010			September 30, 2009		
	Useful Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
				(In thousands)			
Customer contracts	10	$6,926	$(6,092)	$834	$6,926	$(5,465)	$1,461

The following table presents actual amortization expense recognized during 2010 and an estimate of future amortization expense based upon our intangible assets at September 30, 2010.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2010	$627
Estimated for the fiscal year ending:	
September 30, 2011	$627
September 30, 2012	43
September 30, 2013	43
September 30, 2014	43
September 30, 2015	43

4. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment.

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2010 and 2009:

	Natural Gas Distribution	Natural Gas Marketing	Total
		(In thousands)	
September 30, 2010			
Assets from risk management activities, current[1]	$ 2,219	$18,356	$ 20,575
Assets from risk management activities, noncurrent	47	890	937
Liabilities from risk management activities, current[1]	(48,942)	(731)	(49,673)
Liabilities from risk management activities, noncurrent	(2,924)	(6,000)	(8,924)
Net assets (liabilities)	$(49,600)	$12,515	$(37,085)
September 30, 2009			
Assets from risk management activities, current[2]	$ 4,395	$27,248	$ 31,643
Assets from risk management activities, noncurrent	1,620	12,415	14,035
Liabilities from risk management activities, current	(20,181)	(1,301)	(21,482)
Liabilities from risk management activities, noncurrent	—	—	—
Net assets (liabilities)	$(14,166)	$38,362	$ 24,196

(1) Includes $24.9 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

(2) Includes $11.7 million of cash held on deposit to collateralize certain financial instruments which is classified as current risk management assets.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our natural gas distribution customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. If the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2009-2010 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 29 percent, or 26.9 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $6.38 per Mcf. We have not designated these financial instruments as hedges.

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

Nonregulated Commodity Risk Management Activities

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

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 59 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments.

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

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2010, AEH had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $350 million unsecured 7.375% Senior Notes that will mature in May 2011 through the issuance of 30-year unsecured senior notes in June 2011. Additionally, we anticipate issuing $250 million of 30-year unsecured senior notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into five Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges of an anticipated transaction.

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In fiscal years 2004 through 2009, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the issuance of long-term debt and senior notes. In October 2004, we settled four Treasury lock agreements associated with the permanent financing of our TXU Gas acquisition with a net $43.8 million payment to the counterparties. In June 2007, we settled a Treasury lock agreement associated with the issuance of our $250 million 6.35% Senior notes with the receipt of $2.9 million from the counterparties, and in March 2009 we settled an agreement associated with the issuance of our $450 million 8.50% senior notes with the receipt of $1.9 million from the counterparty.

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

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and income statements.

As of September 30, 2010, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2010, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(13,785)	(1,770)
	Cash Flow	—	38,158	(1,480)
	Not designated	34,276	34,779	1,255
		34,276	59,152	(1,995)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of September 30, 2010 and 2009. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $24.9 million and $11.7 million of cash held on deposit in margin accounts as of September 30, 2010 and 2009 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
		(In thousands)		
September 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

(1) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
September 30, 2009				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts . .	Other current assets	$ —	$ 53,526	$ 53,526
Noncurrent commodity contracts	Deferred charges and other assets	—	6,800	6,800
Liability Financial Instruments				
Current commodity contracts . .	Other current liabilities	—	(47,146)	(47,146)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(999)	(999)
Total		—	12,181	12,181
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts . .	Other current assets	4,395	27,559	31,954
Noncurrent commodity contracts	Deferred charges and other assets	1,620	7,964	9,584
Liability Financial Instruments				
Current commodity contracts . .	Other current liabilities	(20,181)	(19,657)	(39,838)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,349)	(1,349)
Total		(14,166)	14,517	351
Total Financial Instruments		$(14,166)	$ 26,698	$ 12,532

(1) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our consolidated income statement, by operating segment, as applicable, for the years ended September 30, 2010, 2009 and 2008.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2010, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $51.8 million, $6.4 million and $46.0 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2010, 2009 and 2008 is presented below.

	Fiscal Year Ended September 30, 2010		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$31,397	$3,253	$34,650
Fair value adjustment for natural gas inventory designated as the hedged item	16,557	3,310	19,867
Total impact on revenue	$47,954	$6,563	$54,517
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (1,272)	$ —	$ (1,272)
Timing ineffectiveness	49,226	6,563	55,789
	$47,954	$6,563	$54,517

	Fiscal Year Ended September 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 37,967	$ 7,153	$ 45,120
Fair value adjustment for natural gas inventory designated as the hedged item	(25,501)	(3,330)	(28,831)
Total impact on revenue	$ 12,466	$ 3,823	$ 16,289
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 5,958	$ —	$ 5,958
Timing ineffectiveness	6,508	3,823	10,331
	$ 12,466	$ 3,823	$ 16,289

	Fiscal Year Ended September 30, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$30,572	$4,941	$35,513
Fair value adjustment for natural gas inventory designated as the hedged item	6,281	482	6,763
Total impact on revenue	$36,853	$5,423	$42,276
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (2,841)	$ —	$ (2,841)
Timing ineffectiveness	39,694	5,423	45,117
	$36,853	$5,423	$42,276

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2010, 2009 and 2008 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(48,095)	$3,286	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	(2,717)	—	(2,717)
Total impact on revenue	—	(50,812)	3,286	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$(50,812)	$3,286	$(50,204)

	Fiscal Year Ended September 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(162,283)	$25,743	$(136,540)
Loss arising from ineffective portion of commodity contracts	—	(9,888)	—	(9,888)
Total impact on revenue	—	(172,171)	25,743	(146,428)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(4,070)	—	—	(4,070)
Total impact from cash flow hedges	$(4,070)	$(172,171)	$25,743	$(150,498)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Fiscal Year Ended September 30, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(12,739)	$9,468	$(3,271)
Gain arising from ineffective portion of commodity contracts	—	3,720	—	3,720
Total impact on revenue	—	(9,019)	9,468	449
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(5,076)	—	—	(5,076)
Total impact from cash flow hedges	$(5,076)	$ (9,019)	$9,468	$(4,627)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2010 and 2009. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Fiscal Year Ended September 30	
	2010	2009
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ 343	$ 1,221
Forward commodity contracts	(34,296)	(72,683)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	1,687	2,385
Forward commodity contracts	27,333	83,290
Total other comprehensive income (loss) from hedging, net of tax[1]	$ (4,933)	$ 14,213

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2010. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into on September 30, 2010 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2011	$(1,687)	$(16,131)	$(17,818)
2012	(1,687)	(3,265)	(4,952)
2013	(1,687)	(1,528)	(3,215)
2014	(1,687)	(1,178)	(2,865)
2015	179	(7)	172
Thereafter	758	—	758
Total[1]	$(5,811)	$(22,109)	$(27,920)

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2010, 2009 and 2008 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Fiscal Year Ended September 30		
	2010	2009	2008
		(In thousands)	
Natural gas marketing commodity contracts	$15,380	$43,483	$(37,200)
Pipeline, storage and other commodity contracts	2	(6,614)	1,139
Total impact on revenue	$15,382	$36,869	$(36,061)

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Effective October 1, 2009, the authoritative guidance related to nonrecurring fair value measurements became effective for us with respect to asset retirement obligations, most nonfinancial assets and liabilities that may be acquired in a business combination and impairment analyses performed for nonfinancial assets. The adoption of the FASB's fair value guidance for the reporting of these nonrecurring fair value measurements did not have a material impact on our financial position, results of operations or cash flows for the year ended September 30, 2010.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 8 below.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2010 and 2009. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Natural gas marketing segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground					
Natural gas marketing segment	51,032	—	—	—	51,032
Pipeline, storage and other segment[4]	6,475	—	—	—	6,475
Total gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities	41,466	—	—	—	41,466
Total assets	$117,517	$44,728	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Natural gas marketing segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 6,015	$ —	$ —	$ 6,015
Natural gas marketing segment	34,281	61,568	—	(56,186)	39,663
Total financial instruments	34,281	67,583	—	(56,186)	45,678
Hedged portion of gas stored underground					
Natural gas marketing segment	47,967	—	—	—	47,967
Pipeline, storage and other segment[4]	6,789	—	—	—	6,789
Total gas stored underground	54,756	—	—	—	54,756
Available-for-sale securities	41,699	—	—	—	41,699
Total assets	$130,736	$67,583	$ —	$(56,186)	$142,133
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$20,181	$ —	$ —	$ 20,181
Natural gas marketing segment	48,268	20,883	—	(67,850)	1,301
Total liabilities	$ 48,268	$41,064	$ —	$(67,850)	$ 21,482

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting agreements and the remaining $12.3 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2009 we had $11.7 million of cash held in margin accounts to collateralize certain financial instruments which has been classified as current risk management assets.

(4) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. As noted above, fair value disclosures for pension and post-retirement plan assets became effective for us on October 1, 2009. These disclosures are included in Note 8. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of September 30, 2010:

	September 30, 2010
	(In thousands)
Carrying Amount	$2,172,696
Fair Value	$2,439,349

6. Debt

Long-term debt

Long-term debt at September 30, 2010 and 2009 consisted of the following:

	2010	2009
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 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
Rental property, propane and other term notes due in installments through 2013	393	524
Total long-term debt	2,172,696	2,172,827
Less:		
Original issue discount on unsecured senior notes and debentures	(3,014)	(3,296)
Current maturities	(360,131)	(131)
	$1,809,551	$2,169,400

As noted above, our Unsecured 7.375% Senior Notes will mature in May 2011 and our Series A, 1995-2, 6.27% medium term notes will mature in December 2010; accordingly, these have been classified within the current maturities of long-term debt.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. At September 30, 2010 and 2009, there was $126.1 million and $72.6 million outstanding under our commercial paper program. As of September 30, 2010 our commercial paper had maturities of less than one week with interest rates of 0.34 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year $566.7 million unsecured facility, expiring December 15, 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At September 30, 2010, there were no borrowings under this facility, but we had $126.1 million of commercial paper outstanding leaving $440.6 million available.

The second facility is a $200 million unsecured 364-day facility expiring October 22, 2010, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.75 percent to 3.00 percent, based on the Company's credit ratings. At September 30, 2010, there were no borrowings outstanding under this facility. In October 2010, this facility was replaced with a $200 million 180-day facility on substantially the same terms, which expires in April 2011.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2010, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these 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, 2010, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $200 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility, (ii) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the 364-day revolving credit facility or (iii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011 for up to $350 million. There was $132.4 million outstanding under this facility at September 30, 2010.

Nonregulated Operations

On December 10, 2009, AEM and the participating banks amended and restated AEM's $450 million committed revolving credit facility extending it to December 9, 2010. We are currently in discussions with our third-party lenders to replace this facility with a $200 million three-year facility with an accordion feature that could increase AEM's borrowing capacity to $500 million.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a one-month interest period) as in effect from time to time; and (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent plus 0.50 percent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2010, there were no borrowings outstanding under this credit facility. However, at September 30, 2010, AEM letters of credit totaling $22.9 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $169.3 million at September 30, 2010.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2010, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.94 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at September 30, 2010, AEM's net working capital was $180.1 million and its tangible net worth was $194.6 million.

To supplement borrowings under this facility, as of September 30, 2010, AEM had a $300 million intercompany demand credit facility with AEH, which bears interest at the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. There were no borrowings outstanding under this facility at September 30, 2010.

Finally, as of September 30, 2010, AEH had a $200 million intercompany demand credit facility with AEC, which bore interest at greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. In October 2010, we received regulatory approval to increase this facility, effective December 1, 2010 through December 31, 2011, to $350 million with substantially the same terms. There were no borrowings outstanding under this facility at September 30, 2010.

Shelf Registration

On March 31, 2010, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance.

We received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, 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.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of September 30, 2010. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2010 were as follows (in thousands):

2011	$ 360,131
2012	2,434
2013	250,131
2014	—
2015	500,000
Thereafter	1,060,000
	$2,172,696

7. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. We will receive the balance of the shares at the conclusion of the repurchase program. The specific number of shares we will ultimately repurchase in the transaction will be based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. The agreement is scheduled to end in March 2011, although the termination date may be accelerated. As a result of this transaction, our weighted-average shares outstanding were reduced during the last three months of fiscal 2010. Beginning with our fourth fiscal quarter, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares repurchased as they were delivered to us and the $100 million purchase price was recorded as a reduction in shareholders' equity. The repurchase transaction added $0.01 to fiscal 2010 earnings per share.

Stock-Based Compensation Plans

Total stock-based compensation expense was $12.7 million, $14.5 million and $14.0 million for the fiscal years ended September 30, 2010, 2009 and 2008, 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, time-lapse restricted stock units, 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, 2010, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 848,730 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Employees who are granted shares of time-lapse restricted stock under our LTIP have a nonforfeitable right to dividends that are paid at the same rate at which they are paid on shares of stock without restrictions. In addition, employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Both time-lapse restricted stock and time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in either the time-lapse restricted stock or time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividends that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividends on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2010, 2009 and 2008:

	2010		2009		2008	
	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	1,295,841	$27.23	1,096,770	$29.04	948,717	$28.95
Granted	551,278	29.07	711,909	25.76	547,845	27.90
Vested	(493,957)	29.24	(499,267)	29.05	(380,895)	27.17
Forfeited	(59,202)	26.54	(13,571)	28.92	(18,897)	29.32
Nonvested at end of year	1,293,960	$27.28	1,295,841	$27.23	1,096,770	$29.04

As of September 30, 2010, there was $18.2 million of total unrecognized compensation cost related to nonvested time-lapse restricted shares and restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.6 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2010, 2009 and 2008 was $14.4 million, $14.5 million and $10.3 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2010		2009		2008	
	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	611,227	$21.88	913,841	$22.54	920,841	$22.54
Granted	—	—	—	—	—	—
Exercised	(176,265)	20.44	(130,965)	21.99	(7,000)	21.90
Forfeited	—	—	—	—	—	—
Expired	—	—	(171,649)	25.31	—	—
Outstanding at end of year[1]	434,962	$22.46	611,227	$21.88	913,841	$22.54
Exercisable at end of year[2]	434,962	$22.46	611,227	$21.88	911,492	$22.53

[1] The weighted-average remaining contractual life for outstanding options was 1.6 years, 2.4 years, and 3.4 years for fiscal years 2010, 2009 and 2008. The aggregate intrinsic value of outstanding options was $1.6 million, $2.1 million and $3.3 million for fiscal years 2010, 2009 and 2008.

[2] The weighted-average remaining contractual life for exercisable options was 1.6 years, 2.4 years and 3.4 years for fiscal years 2010, 2009 and 2008. The aggregate intrinsic value of exercisable options was $1.6 million, $2.1 million and $3.3 million for the fiscal years 2010, 2009 and 2008.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2010, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (In years)	Weighted Average Exercise Price
$21.23 to $22.99	316,205	1.7	$21.84
$23.00 to $26.19	118,757	1.3	$24.12
$21.23 to $26.19	434,962	1.6	$22.46

	Fiscal Year Ended September 30		
	2010	2009	2008
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$3,604	$2,880	$153
Income tax benefit from stock option exercises	$ 547	$ 177	$ 12
Total intrinsic value of options exercised	$ 239	$ 262	$ 26

As of September 30, 2010, there was no unrecognized compensation cost related to nonvested stock options.

Other Plans

Direct Stock Purchase Plan

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

Outside Directors Stock-For-Fee Plan

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

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

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

Other Discretionary Compensation Plans

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

We adopted an incentive plan in October 2001 to give the employees in our nonregulated segments an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

8. Retirement and Post-Retirement Employee Benefit Plans

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

Effective September 30, 2007, we adopted the guidance issued by the FASB related to changes in the accounting rules for defined benefit pension and other postretirement plans. The new standard made a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity.

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

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

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

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2010				
Unrecognized transition obligation	$ —	$ —	$ 4,731	$ 4,731
Unrecognized prior service cost	(842)	—	(10,311)	(11,153)
Unrecognized actuarial loss	159,539	30,753	25,694	215,986
	$158,697	$30,753	$ 20,114	$209,564
September 30, 2009				
Unrecognized transition obligation	$ —	$ —	$ 6,242	$ 6,242
Unrecognized prior service cost	(1,802)	187	(11,761)	(13,376)
Unrecognized actuarial loss	150,989	29,709	24,179	204,877
	$149,187	$29,896	$ 18,660	$197,743

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2010, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to 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 credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applied 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 are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 will be allowed to make a one-time election to migrate from the Plan into our defined contribution plan which will be enhanced, effective January 1, 2011.

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

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

During fiscal 2010 we did make any contributions to our pension plans. In fiscal 2009, we contributed \$21.0 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2008, we voluntarily contributed \$2.3 million to the Union Plan, which achieved the desired level of funding for this plan for the 2007 plan year. Based upon market conditions subsequent to September 30, 2010, the current funded position of the plans and the new funding requirements under the PPA, we believe it is reasonably possible that we will be required to contribute to the Plans in fiscal 2011. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions.

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents asset allocation information for the Master Trust as of September 30, 2010 and 2009.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2010	Actual Allocation September 30 2009
Domestic equities	35%-55%	44.1%	38.5%
International equities	10%-20%	14.4%	12.8%
Fixed income	10%-30%	19.0%	19.6%
Company stock	5%-15%	11.3%	10.9%
Other assets	5%-15%	11.2%	18.2%

At September 30, 2010 and 2009, the Plan held 1,169,700 shares of our common stock, which represented 11.3 percent and 10.9 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.5 million during fiscal 2010 and 2009.

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 September 30 measurement date. Prior to October 1, 2008, the estimates and assumptions were determined based on a June 30 measurement date. As described above, the adoption of new accounting guidance in accordance with accounting principles generally accepted in the United States necessitated a change in our measurement date during fiscal 2009. 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 September 30, 2010 and 2009 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2009, 2008 and June 30, 2007. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2010	2009	2010	2009	2008
Discount rate	5.39%	5.52%	5.52%	7.57%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%	8.25%

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2010 and 2009:

	2010	2009
	(In thousands)	
Accumulated benefit obligation	$ 391,915	$366,770
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 380,045	$337,640
Measurement date change	—	(18,446)
Service cost	13,499	12,951
Interest cost	20,870	24,060
Actuarial loss	19,809	49,807
Benefits paid	(26,687)	(25,967)
Benefit obligation at end of year	407,536	380,045
Change in plan assets:		
Fair value of plan assets at beginning of year	301,146	341,380
Measurement date change	—	(34,935)
Actual return on plan assets	27,249	(332)
Employer contributions	—	21,000
Benefits paid	(26,687)	(25,967)
Fair value of plan assets at end of year	301,708	301,146
Reconciliation:		
Funded status	(105,828)	(78,899)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(105,828)	$ (78,899)

Net periodic pension cost for the Plans for fiscal 2010, 2009 and 2008 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2010	2009	2008
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 13,499	$ 12,951	$ 13,329
Interest cost	20,870	24,060	21,129
Expected return on assets	(25,280)	(24,950)	(25,242)
Amortization of prior service cost	(960)	(946)	(897)
Recognized actuarial loss	9,290	3,742	6,482
Net periodic pension cost	$ 17,419	$ 14,857	$ 14,801

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2010. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2. In addition to the assets shown below, the Master Trust had net accounts receivable of $0.1 million at September 30, 2010 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$116,315	$ —	$ —	$116,315
Money market funds	—	10,013	—	10,013
Registered investment companies	32,601	—	—	32,601
Common/collective trusts	—	48,920	—	48,920
Government securities	5,548	16,296	—	21,844
Corporate bonds	—	33,987	—	33,987
Limited partnerships	—	37,691	—	37,691
Real Estate	—	—	200	200
Total investments at fair value	$154,464	$146,907	$200	$301,571

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. There were no changes in the fair value of the Level 3 assets during the year ended September 30, 2010.

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 (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a 60 percent of covered compensation defined benefit arrangement in which benefits from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of vesting and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 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 September 30, 2010 and 2009 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2009, 2008 and June 30, 2007. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2010	2009	2010	2009	2008
Discount rate	5.39%	5.52%	5.52%	7.57%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2010 and 2009:

	2010	2009
	(In thousands)	
Accumulated benefit obligation	$ 99,673	$ 93,906
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 102,747	$ 91,986
Measurement date change	—	(8,569)
Service cost	2,476	1,985
Interest cost	5,224	6,056
Actuarial loss	3,043	22,366
Benefits paid	(4,571)	(12,722)
Curtailment	—	1,645
Benefit obligation at end of year	108,919	102,747
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	4,571	12,722
Benefits paid	(4,571)	(12,722)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(108,919)	(102,747)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(108,919)	$(102,747)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$—	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$—	$41,466
As of September 30, 2009:				
Domestic equity mutual funds	$26,012	$3,012	$—	$29,024
Foreign equity mutual funds	4,047	893	—	4,940
Money market funds	7,735	—	—	7,735
	$37,794	$3,905	$—	$41,699

In fiscal 2009, we recorded a $5.4 million noncash charge to impair certain available-for sale investments during the year ended September 30, 2009 due to the conditions of the financial markets at that time. At September 30, 2010, we did not maintain any investments that are in an unrealized loss position.

The following table sets forth by level, within the fair value hierarchy, the fair value of the assets used to fund the Company's supplemental executive benefit plans as of September 30, 2010. The methods used to determine fair value for the assets held by the Supplemental Executive Benefit Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$499	$—	$ 499
Registered investment companies	40,967	—	—	40,967
Total investments at fair value	$40,967	$499	$—	$41,466

Net periodic pension cost for the supplemental plans for fiscal 2010, 2009 and 2008 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2010	2009	2008
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$2,476	$ 1,985	$2,184
Interest cost	5,224	6,056	5,816
Amortization of transition asset	—	—	—
Amortization of prior service cost	187	212	212
Recognized actuarial loss	1,999	324	1,222
Curtailment	—	1,645	—
Net periodic pension cost	$9,886	$10,222	$9,434

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 2010 and 2009 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2010	2009
	(In thousands)	
Projected Benefit Obligation	$108,919	$102,747
Accumulated Benefit Obligation	99,673	93,906
Fair Value of Plan Assets	—	—

Estimated Future Benefit Payments

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

	Pension Plans	Supplemental Plans
	(In thousands)	
2011	$ 31,345	$ 7,513
2012	30,586	24,751
2013	29,714	6,820
2014	29,188	4,709
2015	29,405	6,449
2016-2020	141,335	42,766

Postretirement Benefits

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

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Atmos Retiree Medical Plan. Starting on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Atmos Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional 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 $13.0 million to our postretirement benefits plan during fiscal 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2010 and 2009.

Security Class	Actual Allocation September 30 2010	2009
Diversified investment funds	97.5%	98.1%
Cash and cash equivalents	2.5%	1.9%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 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 September 30, 2010 and 2009 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2009, 2008 and June 30, 2007. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2010	2009	2010	2009	2008
Discount rate	5.39%	5.52%	5.52%	7.57%	6.30%
Expected return on plan assets	5.00%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	7.50%	7.50%	8.00%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2016	2014	2015	2015	2011

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2010 and 2009:

	2010	2009
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 209,732	$ 193,997
Measurement date change	—	(15,024)
Service cost	13,439	11,786
Interest cost	12,071	14,080
Plan participants' contributions	2,734	2,741
Actuarial loss	2,980	24,334
Benefits paid	(12,722)	(10,537)
Subsidy payments	—	116
Plan amendments	—	(11,761)
Benefit obligation at end of year	228,234	209,732
Change in plan assets:		
Fair value of plan assets at beginning of year	47,646	48,072
Measurement date change	—	(4,128)
Actual return on plan assets	3,551	1,394
Employer contributions	11,824	10,104
Plan participants' contributions	2,734	2,741
Benefits paid	(12,722)	(10,537)
Fair value of plan assets at end of year	53,033	47,646
Reconciliation:		
Funded status	(175,201)	(162,086)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(175,201)	$(162,086)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net periodic postretirement cost for fiscal 2010, 2009 and 2008 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2010	2009	2008
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$13,439	$11,786	$13,367
Interest cost	12,071	14,080	11,648
Expected return on assets	(2,460)	(2,292)	(2,861)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	—	—
Recognized actuarial loss	374	—	—
Net periodic postretirement cost	$23,485	$25,085	$23,665

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:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 3,802	$ (3,178)
Effect on postretirement benefit obligation	$26,219	$(22,219)

We are currently recovering other postretirement benefits costs through our regulated rates under accrual accounting as prescribed by accounting principles generally accepted in the United States 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 this accounting method 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.

The following table sets forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2010. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,307	$—	$ 1,307
Registered investment companies	51,726	—	—	51,726
Total investments at fair value	$51,726	$1,307	$—	$53,033

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Estimated Future Benefit Payments

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

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2011	$13,006	$ 2,931	$—	$ 15,937
2012	11,624	3,429	—	15,053
2013	12,960	3,848	—	16,808
2014	14,378	4,294	—	18,672
2015	15,504	4,713	—	20,217
2016-2020	87,039	31,041	—	118,080

Defined Contribution Plans

As of September 30, 2010, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Marketing, LLC 401K Profit-Sharing Plan (the AEM 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees will participate in our defined contribution plan, which has been enhanced, effective January 1, 2011. Current employees participating in the Pension Account Plan as of October 1, 2010 will be allowed to make a one-time election to migrate from the Plan into our defined contribution plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $9.8 million, $9.3 million, and $8.9 million for fiscal years 2010, 2009 and 2008. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for fiscal years 2010, 2009 or 2008. At September 30, 2010 and 2009, the Retirement Savings Plan held 4.3 percent and 3.8 percent of our outstanding common stock.

The AEM 401K Profit-Sharing Plan covers substantially all AEM employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to three percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEM 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEM 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.3 million, $1.2 million and $1.2 million for fiscal years 2010, 2009 and 2008.

9. Details of Selected Consolidated Balance Sheet Captions

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

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2010 and 2009:

	September 30	
	2010	2009
	(In thousands)	
Billed accounts receivable	$223,129	$179,667
Unbilled revenue	47,423	42,618
Other accounts receivable	15,356	21,999
Total accounts receivable	285,908	244,284
Less: allowance for doubtful accounts	(12,701)	(11,478)
Net accounts receivable	$273,207	$232,806

Other current assets

Other current assets as of September 30, 2010 and 2009 were comprised of the following accounts.

	September 30 2010	September 30 2009
	(In thousands)	
Assets from risk management activities	$ 20,575	$ 31,643
Deferred gas costs	22,701	22,233
Taxes receivable	19,382	15,115
Current deferred tax asset	53,926	—
Prepaid expenses	24,754	21,807
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	3,940	3,349
Asset held for sale	—	19,925
Other	2,744	15,158
Total	$150,995	$132,203

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. During the fiscal year ended September 30, 2009, management approved a plan to pursue the sale of the storage facility project which was expected to be completed within fiscal 2010; therefore the assets were classified in other current assets as an asset held for sale as of September 30, 2009. In March 2010, we entered into an option and acquisition agreement with a third party, which provides the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. If the option is exercised, we will retain a non-controlling equity position in Fort Necessity and will share in a percentage of the profits. In July 2010, we signed an extension to the option and acquisition agreement which gives the third party until March 2011 to exercise the option to develop the project. Due to the current status of the project, the assets are presented as a long-term asset as of September 30, 2010 and are no longer classified as an asset held for sale.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2010 and 2009:

	September 30 2010	September 30 2009
	(In thousands)	
Production plant	$ 17,360	$ 23,359
Storage plant	193,155	156,466
Transmission plant	1,108,398	1,029,487
Distribution plant	4,339,277	4,103,531
General plant	671,953	614,324
Intangible plant	54,253	54,253
	6,384,396	5,981,420
Construction in progress	157,922	105,198
	6,542,318	6,086,618
Less: accumulated depreciation and amortization	(1,749,243)	(1,647,515)
Net property, plant and equipment	$ 4,793,075	$ 4,439,103

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2010 and 2009 were comprised of the following accounts.

	September 30	
	2010	2009
	(In thousands)	
Marketable securities	$ 41,466	$ 41,699
Regulatory assets	254,809	251,242
Deferred financing costs	35,761	40,854
Assets from risk management activities	937	14,035
Other	22,403	11,146
Total	$355,376	$358,976

Other current liabilities

Other current liabilities as of September 30, 2010 and 2009 were comprised of the following accounts.

	September 30	
	2010	2009
	(In thousands)	
Customer deposits	$ 63,733	$ 69,966
Accrued employee costs	40,642	40,582
Deferred gas costs	43,333	110,754
Accrued interest	42,901	46,495
Liabilities from risk management activities	49,673	21,482
Taxes payable	56,616	49,821
Pension and postretirement obligations	14,815	28,712
Regulatory cost of removal accrual	30,953	14,342
Current deferred tax liability	—	9,054
Other	70,974	66,111
Total	$413,640	$457,319

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2010 and 2009 were comprised of the following accounts.

	September 30	
	2010	2009
	(In thousands)	
Postretirement obligations	$167,899	$154,784
Retirement plan obligations	207,234	160,236
Customer advances for construction	15,466	16,907
Regulatory liabilities	6,112	7,960
Asset retirement obligation	11,432	13,037
Uncertain tax positions	6,731	6,731
Liabilities from risk management activities	8,924	—
Other	6,366	8,503
Total	$430,164	$368,158

10. Earnings Per Share

As discussed in Note 2, since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share as of October 1, 2009. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. The presentation of earnings per share for previously reported periods has been adjusted to reflect the retrospective adoption of this standard.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	2010	2009	2008
	(In thousands, except per share data)		
Basic Earnings Per Share			
Net income	$205,839	$190,978	$180,331
Less: Income allocated to participating securities	2,106	1,784	1,387
Net income available to common shareholders	$203,733	$189,194	$178,944
Basic weighted average shares outstanding	91,852	91,117	89,385
Net income per share — Basic	$ 2.22	$ 2.08	$ 2.00
Diluted Earnings Per Share			
Net income available to common shareholders	$203,733	$189,194	$178,944
Effect of dilutive stock options and other shares	5	4	3
Net income available to common shareholders	$203,738	$189,198	$178,947
Basic weighted average shares outstanding	91,852	91,117	89,385
Additional dilutive stock options and other shares	570	503	556
Diluted weighted average shares outstanding	92,422	91,620	89,941
Net income per share — Diluted	$ 2.20	$ 2.07	$ 1.99

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2010 and 2008. There were approximately 70,000 out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2009.

11. Income Taxes

The components of income tax expense from continuing operations for 2010, 2009 and 2008 were as follows:

	2010	2009	2008
		(In thousands)	
Current			
Federal	$ (73,794)	$ (37,042)	$ 7,161
State	6,133	7,964	7,696
Deferred			
Federal	184,800	138,959	85,573
State	11,931	(9,200)	12,367
Investment tax credits	(283)	(390)	(424)
	$128,787	$100,291	$112,373

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 2010, 2009 and 2008 are set forth below:

	2010	2009	2008
		(In thousands)	
Tax at statutory rate of 35%	$117,119	$101,944	$102,446
Common stock dividends deductible for tax reporting	(1,785)	(1,591)	(1,363)
Tax exempt income	(2)	(153)	—
State taxes (net of federal benefit)	11,742	(803)	12,523
Other, net	1,713	894	(1,233)
Income tax expense	$128,787	$100,291	$112,373

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, 2010 and 2009 are presented below:

	2010	2009
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	$ —	$ 6,771
Accruals not currently deductible for tax purposes	9,182	7,664
Customer advances	5,723	6,256
Nonqualified benefit plans	43,427	41,359
Postretirement benefits	57,386	53,074
Treasury lock agreements	3,211	4,404
Unamortized investment tax credit	183	192
Regulatory liabilities	217	834
Tax net operating loss and credit carryforwards	63,621	1,997
Difference between book and tax on mark to market accounting	2,159	—
Other, net	4,561	6,311
Total deferred tax assets	189,670	128,862
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(940,914)	(672,763)
Pension funding	(14,936)	(21,379)
Gas cost adjustments	(6,473)	(2,459)
Regulatory assets	(219)	(195)
Cost expensed for tax purposes and capitalized for book purposes	(2,330)	—
Difference between book and tax on mark to market accounting	—	(12,060)
Total deferred tax liabilities	(964,872)	(708,856)
Net deferred tax liabilities	$(775,202)	$(579,994)
Deferred credits for rate regulated entities	$ 587	$ 2,253

At September 30, 2010, we had $14.3 million of federal alternative minimum tax credit carryforwards, $41.2 million of federal net operating loss carryforwards and $8.1 million of state net operating loss carryforwards. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2028. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2015 and 2028.

As of September 30, 2010 and 2009, we had recorded liabilities associated with uncertain tax positions totaling $6.7 million. The realization of all of these tax benefits would reduce our income tax expense by approximately $6.7 million. There were no changes in unrecognized tax benefits as a result of tax positions taken during the current or prior years or as a result of settlements with taxing authorities for the fiscal year ended September 30, 2010.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.5 million and $0.1 million related to penalty and interest expenses during the fiscal years ended September 30, 2010 and 2009 and a tax benefit of $1.2 million during the fiscal year ended September 30, 2008.

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

12. Commitments and Contingencies

Litigation

Colorado-Kansas Division

Atmos Energy was 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 purported to represent a class of royalty owners, alleged that the defendants had 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 did not specifically allege an amount of damages. We were 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. In September 2009, the court ruled that the plaintiffs in both cases had not provided sufficient evidence to meet the standards of a class action and denied class action status to each of the plaintiffs in both cases. In September 2010, Atmos Energy was dismissed from these cases without liability by the District Court of Stevens County, Kansas.

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

Environmental Matters

Former Manufactured Gas Plant Sites

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

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2010, AEM was committed to purchase 69.5 Bcf within one year, 28.4 Bcf within one to three years and 3.2 Bcf after three years under indexed contracts. AEM is committed to purchase 3.1 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.55 to $6.36 per Mcf. Purchases under these contracts totaled $1,562.8 million, $1,484.5 million and $3,075.0 million for 2010, 2009 and 2008.

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 and fixed prices. The estimated commitments under these contracts as of September 30, 2010 are as follows (in thousands):

2011	$264,525
2012	74,351
2013	5,407
2014	1,903
2015	—
Thereafter	—
	$346,186

Our natural gas marketing and pipeline, storage and other segments maintain long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2010 are as follows (in thousands):

	Natural Gas Marketing	Pipeline, Storage and Other
2011	$18,438	$ 3,572
2012	13,528	2,082
2013	8,557	1,820
2014	4,843	1,820
2015	2,916	910
Thereafter	241	—
	$48,523	$10,204

Other Contingencies

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

The Commission agreed to allow the Company to conduct our own internal investigation into compliance with the Commission's rules. We have completed the investigation and have provided a report on the results of the investigation to the Commission, which report is currently under review by the Commission. We currently are unable to predict the final outcome of this investigation or the potential impact it could have on our financial position, results of operations or cash flows.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. Two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program will commence in fiscal 2011 at a total projected capital cost of \$80 — \$120 million, with completion expected in September 2012.

13. Leases

Leasing Operations

A subsidiary of AEH has constructed electric peaking power-generating plants and associated facilities and entered into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2010 and 2009, we had receivables of \$7.8 million and \$10.8 million and recognized income of \$0.9 million, \$1.2 million and \$1.3 million for fiscal years 2010, 2009 and 2008. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts
	(In thousands)
2011	\$2,973
2012	2,973
2013	1,903
2014	—
2015	—
Thereafter	—
Total minimum lease receipts	\$7,849

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 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 million at September 30, 2010 and 2009. Accumulated depreciation for these capital leases totaled $0.8 million at September 30, 2010 and 2009. 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, 2010 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2011	$ 186	$ 18,240
2012	186	17,356
2013	186	16,051
2014	186	15,958
2015	186	15,249
Thereafter	450	134,330
Total minimum lease payments	1,380	$217,184
Less amount representing interest	497	
Present value of net minimum lease payments	$ 883	

Consolidated lease and rental expense amounted to $16.0 million, $13.6 million and $14.2 million for fiscal 2010, 2009 and 2008.

14. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the natural gas distribution segment is mitigated by the large number of individual customers and diversity in our customer base. The credit risk for our other segments is not significant.

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

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2010, 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, 2010 and 2009.

	September 30, 2010	September 30, 2009
Investment grade	47%	53%
Non-investment grade	53%	47%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2010. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment(1)	Natural Gas Marketing Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 973	$ 973
Non-investment grade counterparties	—	5,959	5,959
	$—	$6,932	$6,932

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

15. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for fiscal 2010, 2009 and 2008 are presented below.

	2010	2009	2008
		(In thousands)	
Cash paid for interest	$161,925	$163,554	$139,958
Cash paid (received) for income taxes	$(63,677)	$(36,405)	$ 3,483

There were no significant noncash investing and financing transactions during fiscal 2010, 2009 and 2008. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

16. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage business as well as other nonregulated businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

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

We operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which includes our nonregulated natural gas transmission and storage services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

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, 2010					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,911,623	$ 97,023	$1,754,523	$26,521	$ —	$4,789,690
Intersegment revenues	870	105,990	396,741	8,797	(512,398)	—
	2,912,493	203,013	2,151,264	35,318	(512,398)	4,789,690
Purchased gas cost	1,863,046	—	2,065,313	7,178	(510,788)	3,424,749
Gross profit	1,049,447	203,013	85,951	28,140	(1,610)	1,364,941
Operating expenses						
Operation and maintenance	362,882	72,249	26,390	8,127	(1,610)	468,038
Depreciation and amortization	190,518	21,368	2,450	2,624	—	216,960
Taxes, other than income	173,593	12,358	2,859	1,697	—	190,507
Total operating expenses	726,993	105,975	31,699	12,448	(1,610)	875,505
Operating income	322,454	97,038	54,252	15,692	—	489,436
Miscellaneous income (expense)	1,384	135	2,280	3,083	(7,221)	(339)
Interest charges	118,430	31,174	9,280	2,808	(7,221)	154,471
Income before income taxes	205,408	65,999	47,252	15,967	—	334,626
Income tax expense	79,459	24,513	19,523	5,292	—	128,787
Net income	$ 125,949	$ 41,486	$ 27,729	$10,675	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 5,410	$ 3,576	$ —	$ 542,636

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,983,966	$119,427	$1,832,912	$32,775	$ —	$4,969,080
Intersegment revenues	799	90,231	503,935	9,149	(604,114)	—
	2,984,765	209,658	2,336,847	41,924	(604,114)	4,969,080
Purchased gas cost	1,960,137	—	2,252,235	12,428	(602,422)	3,622,378
Gross profit	1,024,628	209,658	84,612	29,496	(1,692)	1,346,702
Operating expenses						
Operation and maintenance	369,429	85,249	34,201	7,167	(2,036)	494,010
Depreciation and amortization	192,274	20,413	1,590	2,931	—	217,208
Taxes, other than income	169,312	10,231	2,271	886	—	182,700
Asset impairments	4,599	602	146	35	—	5,382
Total operating expenses	735,614	116,495	38,208	11,019	(2,036)	899,300
Operating income	289,014	93,163	46,404	18,477	344	447,402
Miscellaneous income (expense)	5,766	1,433	537	6,253	(17,292)	(3,303)
Interest charges	124,055	30,982	12,911	1,830	(16,948)	152,830
Income before income taxes	170,725	63,614	34,030	22,900	—	291,269
Income tax expense	53,918	22,558	13,836	9,979	—	100,291
Net income	$ 116,807	$ 41,056	$ 20,194	$12,921	$ —	$ 190,978
Capital expenditures	$ 379,500	$108,332	$ 242	$21,420	$ —	$ 509,494

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$3,654,338	$108,116	$3,436,563	$22,288	$ —	$7,221,305
Intersegment revenues	792	87,801	851,299	9,421	(949,313)	—
	3,655,130	195,917	4,287,862	31,709	(949,313)	7,221,305
Purchased gas cost	2,649,064	—	4,194,841	3,396	(947,322)	5,899,979
Gross profit	1,006,066	195,917	93,021	28,313	(1,991)	1,321,326
Operating expenses						
Operation and maintenance	389,244	77,439	30,903	4,983	(2,335)	500,234
Depreciation and amortization	177,205	19,899	1,546	1,792	—	200,442
Taxes, other than income	178,452	8,834	4,180	1,289	—	192,755
Total operating expenses	744,901	106,172	36,629	8,064	(2,335)	893,431
Operating income	261,165	89,745	56,392	20,249	344	427,895
Miscellaneous income	9,689	1,354	2,022	8,428	(18,762)	2,731
Interest charges	117,933	27,049	9,036	2,322	(18,418)	137,922
Income before income taxes	152,921	64,050	49,378	26,355	—	292,704
Income tax expense	60,273	22,625	19,389	10,086	—	112,373
Net income	$ 92,648	$ 41,425	$ 29,989	$16,269	$ —	$ 180,331
Capital expenditures	$ 386,542	$ 75,071	$ 340	$10,320	$ —	$ 472,273

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

	2010	2009	2008
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,826,752	$1,830,140	$2,131,447
Commercial	808,981	838,184	1,077,056
Industrial	112,366	135,633	212,531
Public authority and other	70,580	89,183	137,821
Total gas sales revenues	2,818,679	2,893,140	3,558,855
Transportation revenues	61,384	59,115	59,712
Other gas revenues	31,560	31,711	35,771
Total natural gas distribution revenues	2,911,623	2,983,966	3,654,338
Regulated transmission and storage revenues	97,023	119,427	108,116
Natural gas marketing revenues	1,754,523	1,832,912	3,436,563
Pipeline, storage and other revenues	26,521	32,775	22,288
Total operating revenues	$4,789,690	$4,969,080	$7,221,305

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at September 30, 2010 and 2009 by segment is presented in the following tables:

	September 30, 2010					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
ASSETS						
Property, plant and equipment, net	$3,959,112	$748,947	$ 11,082	$ 73,934	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	—	(618,767)	—
Current assets						
Cash and cash equivalents	31,952	—	99,644	356	—	131,952
Assets from risk management activities	2,219	—	18,356	3,372	(3,372)	20,575
Other current assets	528,655	19,504	179,666	145,361	(150,521)	722,665
Intercompany receivables	546,313	—	—	123,080	(669,393)	—
Total current assets	1,109,139	19,504	297,666	272,169	(823,286)	875,192
Intangible assets	—	—	834	—	—	834
Goodwill	572,262	132,341	24,282	10,429	—	739,314
Noncurrent assets from risk management activities	47	—	1,214	3	(327)	937
Deferred charges and other assets	324,707	13,037	1,404	15,291	—	354,439
	$6,586,130	$913,829	$334,386	$371,826	$(1,442,380)	$6,763,791
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,178,348	$212,687	$ 63,650	$344,526	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	63,650	344,788	(620,863)	3,987,899
Current liabilities						
Current maturities of long-term debt	360,000	—	—	131	—	360,131
Short-term debt	258,488	—	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	4,098	5	(3,372)	49,673
Other current liabilities	473,076	10,949	149,220	12,967	(16,037)	630,175
Intercompany payables	—	543,007	126,386	—	(669,393)	—
Total current liabilities	1,140,506	553,956	279,704	13,103	(821,190)	1,166,079
Deferred income taxes	691,126	142,337	(15,864)	11,529	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	327	(327)	8,924
Regulatory cost of removal obligation	350,521	—	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	896	2,079	—	421,240
	$6,586,130	$913,829	$334,386	$371,826	$(1,442,380)	$6,763,791

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,703,471	$672,829	$ 7,112	$ 55,691	$ —	$4,439,103
Investment in subsidiaries	547,936	—	(2,096)	—	(545,840)	—
Current assets						
Cash and cash equivalents	23,655	—	87,266	282	—	111,203
Assets from risk management activities	4,395	—	27,424	2,765	(2,941)	31,643
Other current assets	499,155	17,017	157,846	112,551	(100,475)	686,094
Intercompany receivables	552,408	—	—	128,104	(680,512)	—
Total current assets	1,079,613	17,017	272,536	243,702	(783,928)	828,940
Intangible assets	—	—	1,461	—	—	1,461
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	1,620	—	12,415	6	(6)	14,035
Deferred charges and other assets	313,644	11,932	1,065	18,300	—	344,941
	$6,217,876	$834,078	$316,775	$328,128	$(1,329,774)	$6,367,083
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,176,761	$171,200	$ 83,354	$293,382	$ (547,936)	$2,176,761
Long-term debt	2,169,007	—	—	393	—	2,169,400
Total capitalization	4,345,768	171,200	83,354	293,775	(547,936)	4,346,161
Current liabilities						
Current maturities of long-term debt	—	—	—	131	—	131
Short-term debt	158,942	—	—	—	(86,392)	72,550
Liabilities from risk management activities	20,181	—	4,060	182	(2,941)	21,482
Other current liabilities	510,749	9,251	116,078	19,167	(11,987)	643,258
Intercompany payables	—	557,190	123,322	—	(680,512)	—
Total current liabilities	689,872	566,441	243,460	19,480	(781,832)	737,421
Deferred income taxes	477,352	92,250	(10,675)	12,013	—	570,940
Noncurrent liabilities from risk management activities	—	—	6	—	(6)	—
Regulatory cost of removal obligation	344,403	—	—	—	—	344,403
Deferred credits and other liabilities	360,481	4,187	630	2,860	—	368,158
	$6,217,876	$834,078	$316,775	$328,128	$(1,329,774)	$6,367,083

17. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2010:				
Operating revenues				
Natural gas distribution	$ 802,894	$1,365,988	$ 405,271	$ 338,340
Regulated transmission and storage	46,860	55,181	44,957	56,015
Natural gas marketing	544,271	692,152	421,406	493,435
Pipeline, storage and other	11,623	9,050	8,196	6,449
Intersegment eliminations	(112,796)	(182,105)	(109,573)	(107,924)
	1,292,852	1,940,266	770,257	786,315
Gross profit	410,849	454,321	253,228	246,543
Operating income	190,596	224,540	34,109	40,191
Net income (loss)	93,330	114,126	(3,154)	1,537
Net income (loss) per basic share	$ 1.00	$ 1.22	$ (0.03)	$ 0.02
Net income (loss) per diluted share	$ 1.00	$ 1.22	$ (0.03)	$ 0.02
Fiscal year 2009:				
Operating revenues				
Natural gas distribution	$1,055,968	$1,230,420	$ 386,985	$ 311,392
Regulated transmission and storage	54,682	59,234	49,345	46,397
Natural gas marketing	787,495	708,658	453,504	387,190
Pipeline, storage and other	16,448	12,272	8,226	4,978
Intersegment eliminations	(198,261)	(189,178)	(117,285)	(99,390)
	1,716,332	1,821,406	780,775	650,567
Gross profit	395,212	460,051	259,640	231,799
Operating income	163,194	226,547	43,683	13,978
Net income (loss)	75,963	129,003	1,964	(15,952)
Net income (loss) per basic share	$ 0.83	$ 1.41	$ 0.02	$ (0.17)
Net income (loss) per diluted share	$ 0.83	$ 1.40	$ 0.02	$ (0.17)

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2010 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2010, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ KIM R. COCKLIN	/s/ FRED E. MEISENHEIMER
Kim R. Cocklin President and Chief Executive Officer	Fred E. Meisenheimer Senior Vice President, Chief Financial Officer and Treasurer

November 12, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2010, 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, 2010, 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, 2010 and 2009, and the related statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2010 of Atmos Energy Corporation and our report dated November 12, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2010

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, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***Other Information.***

Not applicable.

PART III

ITEM 10. ***Directors, Executive Officers and Corporate Governance.***

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011 Information regarding executive officers is included in Part I of this Annual Report on Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance."

ITEM 11. ***Executive Compensation.***

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011.

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

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2011.

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 10.15 are management contracts or compensatory plans or arrangements.

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/ FRED E. MEISENHEIMER

Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Treasurer

Date: November 12, 2010

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin and Fred. E. Meisenheimer, 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/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 12, 2010
/s/ FRED E. MEISENHEIMER Fred E. Meisenheimer	Senior Vice President, Chief Financial Officer and Treasurer	November 12, 2010
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 12, 2010
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 12, 2010
/s/ RICHARD W. CARDIN Richard W. Cardin	Director	November 12, 2010
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 12, 2010
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 12, 2010
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 12, 2010
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 12, 2010
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 12, 2010
/s/ PHILLIP E. NICHOL Phillip E. Nichol	Director	November 12, 2010
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 12, 2010

/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 12, 2010
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 12, 2010
/s/ RICHARD WARE II Richard Ware II	Director	November 12, 2010

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2010

	Balance at Beginning of Period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In thousands)				
2010					
Allowance for doubtful accounts	$11,478	$ 7,694	$—	$ 6,471[1]	$12,701
2009					
Allowance for doubtful accounts	$15,301	$ 7,769	$—	$11,592[1]	$11,478
2008					
Allowance for doubtful accounts	$16,160	$15,655	$—	$16,514[1]	$15,301

[1] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 7⅜% Senior Notes due 2011	Exhibit 99.2 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.7(c)	Global Security for the 5⅛% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(d)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(e)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(f)	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)
4.7(g)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Material Contracts	
10.1	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)
10.2	Revolving Credit Agreement (5 Year Facility), dated as of December 15, 2006, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Wachovia Bank, N.A. as Syndication Agent and Bank of America, N.A., JPMorgan Chase Bank, N.A., and the Royal Bank of Scotland plc as Co-Documentation Agents, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated December 15, 2006 (File No. 1-10042)
10.3	Revolving Credit Agreement (364 Day Facility), dated as of October 22, 2009, among Atmos Energy Corporation, the Lenders from time to time parties thereto, SunTrust Bank as Administrative Agent, Wells Fargo Bank, N.A. as Syndication Agent, and Bank of America, N.A. and U.S. Bank National Association as co-Documentation Agents	Exhibit 10.1 to Form 8-K dated October 22, 2009 (File No. 1-10042)
10.4	Revolving Credit Agreement (180 Day Facility), dated as of October 15, 2010, among Atmos Energy Corporation, the Lenders from time to time parties thereto, SunTrust Bank as Administrative Agent, Wells Fargo Bank, N.A. as Syndication Agent, and Bank of America, N.A. and U.S. Bank National Association as co-Documentation Agents	Exhibit 10.1 to Form 8-K dated October 15, 2010 (File No. 1-10042)
10.5(a)	Fourth Amended and Restated Credit Agreement, dated as of December 10, 2009, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank and as a bank, Fortis Bank SA/NV, New York Branch, a bank organized under the laws of Belgium, as documentation agent, as an issuing bank and as a bank, Société Générale, as syndication agent, as an issuing bank and as a bank and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated December 10, 2009 (File No. 1-10042)
10.5(b)	Second Amended and Restated Intercreditor Agreement, dated as of December 10, 2009, among BNP Paribas and the other financial institutions which may become parties thereto	Exhibit 10.2 to Form 8-K dated December 10, 2009 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.6(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	
10.6(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	
	Executive Compensation Plans and Arrangements	
10.7(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	
10.7(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	
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 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.10(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	
10.10(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	
10.10(d)*	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(e)*	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, Amended and Restated as of January 1, 2010	

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	
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)*	Amendment No. 1 to Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	Exhibit 10.12(b) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.14(c)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.14(d)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.14(e)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.14(f)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.15*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated October 1, 2009)	
12	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	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2010
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
101.INS	XBRL Instance Document***	
101.SCH	XBRL Taxonomy Extension Schema***	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase***	
101.DEF	XBRL Taxonomy Extension Definition Linkbase***	
101.LAB	XBRL Taxonomy Extension Labels Linkbase***	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase***	

* 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.

*** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2011

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**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 ☑ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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

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

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

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2011, was $3,008,806,271.

As of November 14, 2011, the registrant had 90,364,061 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 8, 2012, are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky 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.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
Settled Cities	Represents 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
SRF	Stable Rate Filing
WNA	Weather Normalization Adjustment

PART I

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

ITEM 1. *Business.*

Overview and Strategy

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

Today, we distribute natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in 12 states located primarily in the South, which makes us one of the country's largest natural-gas-only distributors based on number of customers. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

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

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while safely operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have continued to grow our earnings after giving effect to our acquisitions and have experienced more than 25 consecutive years of increasing dividends. Historically, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. In recent years, we have also achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations.

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

Operating Segments

We operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and

- The *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

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

- Atmos Energy Mid-Tex Division,
- Atmos Energy Kentucky/Mid-States Division,
- Atmos Energy Louisiana Division,
- Atmos Energy West Texas Division,
- Atmos Energy Mississippi Division and
- Atmos Energy Colorado-Kansas Division

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

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. See Note 6 in the consolidated financial statements for a complete description of the anticipated sale of our Illinois, Iowa and Missouri service areas. In addition, we transport natural gas for others through our distribution system.

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

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

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

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for approximately 94 percent of residential and commercial margins in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

As of September 30, 2011 we had WNA for our residential and commercial meters in the following service areas for the following periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
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 consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. 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.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically 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 2011 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., 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 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2011 was on February 2, 2011, when sales to customers reached approximately 4.4 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 45 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 primarily by our Atmos Pipeline — Texas Division.

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 regulations or statutes. 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.

Below, we briefly describe our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2011, we held 1,116 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

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

Prior to fiscal 2008, this division operated under one system-wide rate structure. However, in fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that has allowed us, beginning in fiscal 2008, to update rates for customers in these cities through an annual rate review mechanism (RRM). Rates for the remaining 20 percent of this division's customers, primarily the City of Dallas, continue to be updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

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

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 189 communities, some of which of the Missouri communities are located in our Atmos Energy Colorado-Kansas Division.

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 nonregulated segment. Our rates in this division are updated annually through a rate stabilization clause filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, the West Texas Division entered into agreements with its West Texas service areas during fiscal 2008 and its Amarillo and Lubbock service areas during fiscal 2009 to update rates for customers in these service areas through an RRM.

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 parts of Missouri, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

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

Division	Jurisdiction	Effective Date of Last Rate/GRIP Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	08/01/2011	816,976	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	08/01/2010	144,583	(2)	(2)
Kentucky/Mid-States	Georgia	03/31/2010	96,330(3)	8.61%	10.70%
	Illinois	11/01/2000	24,564	9.18%	11.56%
	Iowa	03/01/2001	5,000	(2)	11.00%
	Kentucky	06/01/2010	208,702(4)	(2)	(2)
	Missouri	09/01/2010	66,459	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2011	93,260	8.37%	10.00% - 10.80%
	LGS	07/01/2011	273,775	8.56%	10.40%
Mid-Tex — Settled Cities	Texas	09/01/2011	1,389,187(5)	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/22/2011	1,268,601(5)	8.45%	10.10%
Mid-Tex — Environs GRIP	Texas	06/27/2011	1,268,601(5)	8.60%	10.40%
Mississippi	Mississippi	04/05/2011	239,197	(2)	9.86%
West Texas	Amarillo	08/01/2011	(2)	(2)	9.60%
	Lubbock	09/09/2011	60,892	8.19%	9.60%
	West Texas	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[(6)]	WNA	Performance-Based Rate Program[(7)]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[(8)]	No	No	110,709
	Kansas	(2)	Yes	Yes	No	128,679
Kentucky/Mid-States	Georgia	52/48	No	Yes	Yes	63,897
	Illinois	67/33	No	No	No	22,778
	Iowa	57/43	No	No	No	4,334
	Kentucky	(2)	Yes	Yes	Yes	176,246
	Missouri	49/51	No	No	No	56,643
	Tennessee	52/48	Yes	Yes	Yes	133,634
	Virginia	51/49	Yes	Yes	No	23,310
Louisiana.	Trans LA	52/48	No	Yes	No	75,813
	LGS	52/48	No	Yes	No	277,838
Mid-Tex — Settled Cities	Texas	50/50	Yes	Yes	No	1,259,042
Mid-Tex — Dallas & Environs	Texas	51/49	Yes	Yes	No	314,760
Mississippi	Mississippi	50/50	No	Yes	No	266,074
West Texas	Amarillo	52/48	Yes	Yes	No	70,431
	Lubbock	52/48	Yes	Yes	No	73,748
	West Texas	52/48	Yes	Yes	No	155,255

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

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

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.56 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

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

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

(8) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Natural Gas Distribution Sales and Statistical Data - Continuing Operations

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
METERS IN SERVICE, end of year					
Residential	2,855,998	2,836,483	2,826,814	2,834,884	2,815,974
Commercial	261,220	253,339	256,384	259,154	262,260
Industrial	2,008	2,029	2,136	2,183	2,281
Public authority and other	10,212	10,178	9,211	9,197	19,143
Total meters	3,129,438	3,102,029	3,094,545	3,105,418	3,099,658
SALES VOLUMES — MMcf[(2)]					
Gas Sales Volumes					
Residential	161,012	185,143	154,475	157,816	161,493
Commercial	91,215	99,924	88,445	90,992	92,601
Industrial	18,757	18,714	18,242	21,352	22,479
Public authority and other	10,482	10,107	12,393	13,739	12,265
Total gas sales volumes	281,466	313,888	273,555	283,899	288,838
Transportation volumes	132,357	128,965	123,972	133,997	127,066
Total throughput	413,823	442,853	397,527	417,896	415,904
OPERATING REVENUES (000's)[(2)]					
Gas Sales Revenues					
Residential	$1,570,723	$1,784,051	$1,768,082	$2,068,040	$1,924,523
Commercial	698,366	787,433	807,109	1,044,768	941,827
Industrial	106,569	110,280	132,487	208,681	190,812
Public authority and other	69,176	70,402	88,972	137,585	114,087
Total gas sales revenues	2,444,834	2,752,166	2,796,650	3,459,074	3,171,249
Transportation revenues	60,430	59,381	56,961	57,405	56,814
Other gas revenues	26,599	31,091	31,185	35,183	35,448
Total operating revenues	$2,531,863	$2,842,638	$2,884,796	$3,551,662	$3,263,511

Natural Gas Distribution Sales and Statistical Data - Discontinued Operations

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
Meters in service, end of period	83,753	84,011	84,299	86,361	87,469
Sales volumes — MMcf					
Total gas sales volumes	8,461	8,740	8,562	8,777	8,489
Transportation volumes	6,190	6,900	6,719	7,086	8,043
Total throughput	14,651	15,640	15,281	15,863	16,532
Operating revenues (000's)	$80,028	$69,855	$99,969	$103,468	$95,254

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data - Other Consolidated Statistics

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
Inventory storage balance — Bcf	55.0	54.3	57.0	58.3	58.0
Heating degree days[1]					
Actual (weighted average)	2,733	2,780	2,713	2,820	2,879
Percent of normal	99%	102%	100%	100%	100%
Average transportation revenue per Mcf	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ 0.44
Average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ 9.05	$ 8.09
Employees	4,753	4,714	4,691	4,558	4,472

Natural Gas Distribution Sales and Statistical Data by Division

	Fiscal Year Ended September 30, 2011							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,449,673	349,993	331,272	271,346	237,059	216,655	—	2,855,998
Commercial	123,993	43,875	22,379	24,773	25,617	20,583	—	261,220
Industrial	136	798	—	482	501	91	—	2,008
Public authority and other	—	2,423	—	2,833	2,897	2,059	—	10,212
Total meters	1,573,802	397,089	353,651	299,434	266,074	239,388	—	3,129,438
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	77,075	22,273	13,939	16,280	14,077	17,368	—	161,012
Commercial	50,056	13,407	7,448	6,932	6,630	6,742	—	91,215
Industrial	3,105	5,626	—	4,108	5,823	95	—	18,757
Public authority and other	—	1,395	—	3,294	3,418	2,375	—	10,482
Total	130,236	42,701	21,387	30,614	29,948	26,580	—	281,466
Transportation volumes	46,594	38,801	5,893	24,162	5,237	11,670	—	132,357
Total throughput	176,830	81,502	27,280	54,776	35,185	38,250	—	413,823
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 490,484	$152,293	$125,894	$ 99,353	$ 93,042	$ 83,298	$ —	$1,044,364
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 147,967	$ 58,315	$ 42,219	$ 35,908	$ 39,895	$ 31,684	$ (7,905)	$ 348,083
Depreciation and amortization	$ 95,798	$ 29,644	$ 24,460	$ 16,735	$ 13,188	$ 17,084	$ —	$ 196,909
Taxes, other than income	$ 102,515	$ 10,828	$ 8,773	$ 17,024	$ 13,621	$ 8,610	$ —	$ 161,371
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 144,204	$ 53,506	$ 50,442	$ 29,686	$ 26,338	$ 25,920	$ 7,905	$ 338,001
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 220,032	$ 65,766	$ 41,489	$ 40,387	$ 37,115	$ 31,399	$ 60,711	$ 496,899
PROPERTY, PLANT AND EQUIPMENT, EXCLUDING ASSETS HELD FOR SALE (000's)	$1,965,351	$663,837	$431,773	$393,545	$308,891	$311,013	$173,788	$4,248,198
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,920	1,431	3,541	2,707	5,692	—	2,733
Percent of normal	100%	99%	94%	99%	101%	101%	—	99%
Miles of pipe	29,296	12,215	8,333	7,712	6,563	6,750	—	70,869
Employees	1,668	568	438	351	363	287	1,078	4,753

See footnotes following these tables.

	Fiscal Year Ended September 30, 2010							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,429,287	350,238	331,784	271,418	237,304	216,452	—	2,836,483
Commercial	116,240	43,554	22,420	24,919	25,520	20,686	—	253,339
Industrial	145	801	—	484	513	86	—	2,029
Public authority and other	—	2,411	—	2,809	2,896	2,062	—	10,178
Total meters	1,545,672	397,004	354,204	299,630	266,233	239,286	—	3,102,029
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	92,489	22,897	15,810	19,772	15,775	18,400	—	185,143
Commercial	55,916	13,948	7,821	7,892	7,209	7,138	—	99,924
Industrial	3,227	5,615	—	4,317	5,424	131	—	18,714
Public authority and other	—	1,422	—	3,482	3,103	2,100	—	10,107
Total	151,632	43,882	23,631	35,463	31,511	27,769	—	313,888
Transportation volumes	45,822	36,882	5,626	22,429	5,551	12,655	—	128,965
Total throughput	197,454	80,764	29,257	57,892	37,062	40,424	—	442,853
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 475,852	$143,347	$123,344	$105,476	$ 94,203	$ 79,789	$ —	$1,022,011
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 145,166	$ 56,481	$ 43,604	$ 36,696	$ 41,542	$ 30,892	$ 976	$ 355,357
Depreciation and amortization	$ 89,411	$ 28,066	$ 22,986	$ 15,881	$ 12,621	$ 16,182	$ —	$ 185,147
Taxes, other than income	$ 106,620	$ 12,562	$ 10,995	$ 19,390	$ 13,599	$ 8,172	$ —	$ 171,338
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 134,655	$ 46,238	$ 45,759	$ 33,509	$ 26,441	$ 24,543	$ (976)	$ 310,169
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 196,109	$ 62,808	$ 47,193	$ 39,387	$ 28,538	$ 29,792	$ 33,988	$ 437,815
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT (000's)	$1,761,087	$750,225	$413,189	$319,053	$284,195	$300,380	$130,983	$3,959,112
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,924	1,532	3,537	2,734	5,909	—	2,780
Percent of normal	103%	100%	96%	99%	102%	106%	—	102%
Miles of pipe	29,156	12,196	8,381	7,666	6,546	7,175	—	71,120
Employees	1,650	587	439	344	371	284	1,039	4,714

Natural Gas Distribution Sales and Statistical Data by Division - Discontinued Operations

	Fiscal Year Ended September 30, 2011			Fiscal Year Ended September 30, 2010		
	Kentucky/ Mid-States	Colorado-Kansas	Total	Kentucky/ Mid-States	Colorado-Kansas	Total
Meters in service, end of period	83,325	428	83,753	83,577	434	84,011
Sales volumes — MMcf						
Total gas sales volumes	7,963	498	8,461	8,251	489	8,740
Transportation volumes	6,190	—	6,190	6,900	—	6,900
Total throughput	14,153	498	14,651	15,151	489	15,640
Operating income (000's)	$13,395	$1,020	$14,415	$11,628	$657	$12,285

Notes to preceding tables:

(1) 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.

(2) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.

(3) The Other column represents our shared services function, which provides administrative and other support to the Company. Certain costs incurred by this function are not allocated.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements 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. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. Rates are updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. Atmos Pipeline — Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

These operations include 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

	Fiscal Year Ended September 30				
	2011	**2010**	**2009**	**2008**	**2007**
CUSTOMERS, end of year					
Industrial	71	65	68	62	65
Other	156	176	168	189	196
Total	227	241	236	251	261
PIPELINE TRANSPORTATION VOLUMES — MMcf(1)	620,904	634,885	706,132	782,876	699,006
OPERATING REVENUES (000's)(1)	$219,373	$203,013	$209,658	$195,917	$163,229
Employees, at year end	64	62	62	60	54

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

Nonregulated Segment Overview

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin. Certain of these arrangements are with regulatory affiliates, which have been approved by applicable state regulatory commissions.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials) have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher natural gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

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

Nonregulated Sales and Statistical Data

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
CUSTOMERS, end of year					
Industrial	697	652	631	624	677
Municipal	65	61	63	55	68
Other	362	339	321	312	281
Total	1,124	1,052	1,015	991	1,026
INVENTORY STORAGE BALANCE — Bcf	15.7	17.9	19.9	12.4	21.3
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	446,903	420,203	441,081	457,952	423,895
OPERATING REVENUES (000's)[1]	$2,024,893	$2,146,658	$2,283,988	$4,117,299	$2,901,879

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

Ratemaking Activity

Overview

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

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins. Atmos Energy has annual ratemaking mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately 73 percent of our gross margin. We also have accelerated recovery of capital for approximately 11 percent of our gross margin. Combined, we have rate structures with accelerated recovery of all or a portion of our expenditures for approximately 84 percent of our gross margin. Additionally, we have WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 94 percent of our gross margin. Finally, we have the ability to recover the gas cost portion of bad debts for approximately 73 percent of our gross margin. These mechanisms work in tandem to provide substantial insulation from volatile margins, both for the Company and our customers.

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

Although substantial progress has been made in recent years by improving rate design across Atmos Energy's operating areas, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our natural gas distribution revenues in the fiscal years ended September 30, 2011, 2010 and 2009 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $72.4 million, $56.8 million and $54.4 million, became effective in fiscal 2011, 2010 and 2009 as summarized below:

Rate Action	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Rate case filings	$20,502	$23,663	$ 2,959
Infrastructure programs	15,033	18,989	12,049
Annual rate filing mechanisms	35,216	13,757	38,764
Other ratemaking activity	1,675	392	631
	$72,426	$56,801	$54,403

Additionally, the following ratemaking efforts were initiated during fiscal 2011 but had not been completed as of September 30, 2011:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[(1)(2)]	Georgia	$1,192
	PRP[(1)(3)]	Kentucky	2,529
Mississippi	Stable Rate Filing	Mississippi	5,303
West Texas & Lubbock Environs	Rate Case[(4)]	Railroad Commission of Texas (RRC)	545
			$9,569

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Georgia Commission issued a final order on October 5, 2011 approving a $1.2 million increase to operating income.

(3) The Kentucky Commission approved an increase of $2.5 million effective October 1, 2011.

(4) On September 30, 2011 the Company and Commission Staff signed a settlement and submitted to the Commission for their approval.

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

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

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2011 Rate Case Filings:			
West Texas — Amarillo Environs	Texas	$ 78	07/26/2011
Atmos Pipeline — Texas	Texas	20,424	05/01/2011
Total 2011 Rate Case Filings		$20,502	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas(1)	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	
2009 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 2,513	04/01/2009
West Texas	Texas	446	Various
Total 2009 Rate Case Filings		$ 2,959	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

Infrastructure Programs

As discussed above in "Natural Gas Distribution Segment Overview," infrastructure programs such as GRIP allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2011 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2010	$ 72,980	$12,605	07/26/2011
Mid-Tex/Environs	12/2010	107,840	576	06/27/2011
West Texas/Lubbock & WT Cities Environs	12/2010	17,677	343	06/01/2011
Kentucky/Mid-States-Kentucky (1)	09/2011	3,329	468	06/01/2011
Kentucky/Mid-States-Missouri(2)	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States-Georgia(1)	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	
2010 Infrastructure Programs:				
Mid-Tex(3)	12/2009	$ 16,957	$ 2,983	09/01/2010
West Texas	12/2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	12/2009	95,504	13,405	04/20/2010
Kentucky/Mid-States-Missouri(2)	06/2009	3,578	563	03/02/2010
Colorado-Kansas-Kansas(4)	08/2009	6,917	766	12/12/2009
Kentucky/Mid-States-Georgia(1)	09/2008	6,327	909	10/01/2009
Total 2010 Infrastructure Programs		$148,441	$18,989	
2009 Infrastructure Programs:				
Mid-Tex(5)	12/2008	$105,777	$ 2,732	09/09/2009
Atmos Pipeline — Texas	12/2008	51,308	6,342	04/28/2009
Mid-Tex(3)	12/2007	57,385	1,837	01/26/2009
Kentucky/Mid-States-Missouri(2)	03/2008	3,367	408	11/04/2008
Kentucky/Mid-States-Georgia(1)	09/2007	748	198	10/01/2008
West Texas(6)	2007/08	27,425	532	Various
Total 2009 Infrastructure Programs		$246,010	$12,049	

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(3) Increase relates to the City of Dallas and Environs areas of the Mid-Tex Division.

(4) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

(5) Increase relates only to the City of Dallas area of the Mid-Tex Division.

(6) The West Texas Division files GRIP applications related only to the Lubbock Environs and the West Texas Cities Environs. GRIP implemented for this division include investments that related to both calendar years 2007 and 2008. The incremental investment is based on system-wide plant and additional annual operating revenue is applicable to environs customers only.

Annual Rate Filing Mechanisms

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

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2010	$ 5,126	09/27/2011
Mid-Tex	Dallas	12/31/2010	1,084	09/27/2011
West Texas	Lubbock	12/31/2010	319	09/08/2011
West Texas	Amarillo	12/31/2010	(492)	08/01/2011
Louisiana	LGS	12/31/2010	4,109	07/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Settled Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	
2009 Filings:				
Mid-Tex	Settled Cities	12/31/2008	$ 1,979	08/01/2009
West Texas	WT Cities	12/31/2008	6,599	08/01/2009
Louisiana	LGS	12/31/2008	3,307	07/01/2009
Louisiana	TransLa	09/30/2008	611	04/01/2009
Mississippi	Mississippi	06/30/2008	—	N/A
Mid-Tex	Settled Cities	12/31/2007	21,800	11/08/2008
West Texas	WT Cities	12/31/2007	4,468	11/20/2008
Total 2009 Filings			$38,764	

In June 2011, we reached an agreement with the City of Dallas to enter into the DARR. This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

In August 2010, we reached an agreement to extend the RRM in our Mid-Tex Division for an additional two-year period beginning October 1, 2010; however, the Mid-Tex Division will be required to file a general system-wide rate case on or before June 1, 2013. This extension provides for an annual rate adjustment to reflect changes in the Mid-Tex Division's costs of service and additions to capital investment from year to year, without the necessity of filing a general rate case.

The settlement also allows us to expand our existing program to replace steel service lines in the Mid-Tex Division's natural gas delivery system. On October 13, 2010, the City of Dallas approved the recovery of the return, depreciation and taxes associated with the replacement of 100,000 steel service lines across the Mid-Tex Division by September 30, 2012. The RRM in the Mid-Tex Division was entered into as a result of a settlement in the September 20, 2007 Statement of Intent case filed with all Mid-Tex Division cities. Of the 440 incorporated cities served by the Mid-Tex Division, 439 of these cities are part of the RRM process.

The West Texas RRM was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock and Amarillo RRMs were entered into in the spring of 2009. The West Texas Coalition of Cities agreed to extend its RRM for one additional cycle as part of the settlement of this fiscal year's filing.

During fiscal 2011, the RRC's Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expense associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2011 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 641	07/01/2011
Colorado-Kansas	Kansas	Ad Valorem(1)	685	01/01/2011
Colorado-Kansas	Colorado	AMI(2)	349	12/01/2010
Total 2011 Other Rate Activity			$1,675	
2010 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$ 392	01/05/2010
Total 2010 Other Rate Activity			$ 392	
2009 Other Rate Activity:				
Colorado-Kansas	Kansas	Tax Surcharge(3)	$ 631	02/01/2009
Total 2009 Other Rate Activity			$ 631	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

(2) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of our Colorado service area.

(3) In the state of Kansas, the tax surcharge represents a true-up of ad valorem taxes paid versus what is designed to be recovered through base rates.

Other Regulation

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

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity, as well as authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

Competition

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

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2011, we had 4,949 employees, consisting of 4,817 employees in our regulated operations and 132 employees in our nonregulated operations.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, under

"Publications and Filings" under the "Investors" tab, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

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

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2011, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. ***Risk Factors.***

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

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

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

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. If adverse credit conditions were to cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. Such a downgrade could further limit our access to public and/or private credit markets and increase the costs of borrowing under each source of credit.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our nonregulated segment because the commodity financial instruments markets could become unavailable to us. Our nonregulated segment depends primarily upon a committed credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. A significant reduction in the availability of this facility could require us to provide extra liquidity to support its operations or reduce some of the activities of our nonregulated segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

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

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

The slowdown in the U.S. economy in the last few years, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in improving current economic conditions, including the lowering of current high unemployment rates across the U.S. As a result, our customers may seek to use even less gas and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of the health care benefits for our employees.

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

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years. Although the full effects of the Health Care Reform Act should not impact the Company until 2014, the future cost of compliance with the provisions of this legislation is difficult to measure at this time.

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

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics 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, particularly in our nonregulated business segments, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segments 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. 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. 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. 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 before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match 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. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

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

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

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

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

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 76,000 miles of pipeline and distribution lines. The pipeline replacement programs currently underway in several of our divisions typify the preventive maintenance and continual renewal that we perform on our natural gas distribution system in the 12 states in which we currently operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the recent unfortunate pipeline incident in California, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Although we believe these costs are ultimately recoverable through our rates, costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

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

FERC has regulatory authority that affects some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. We are currently under investigation by FERC for possible violations of its posting and competitive bidding regulations for pre-arranged released firm capacity on interstate natural gas pipelines. Should FERC conclude that we have committed such violations of its regulations and levies substantial fines and/or penalties against us, our business, financial condition or financial results could be adversely affected. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

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.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of new federal and state legislative and regulatory initiatives proposed in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. For example, in June 2009, the U.S. House of Representatives approved *The American Clean Energy and Security Act of 2009*, also known as the Waxman-Markey bill or "cap and trade" bill. However, neither this bill nor a related bill in the U.S. Senate, the Clean Energy and Emissions Power Act was passed by Congress. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

Over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

Since the 2006-2007 winter heating season, we have had weather-normalized rates for over 90 percent of our residential and commercial meters, which has substantially mitigated the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather — normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our nonregulated 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. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

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

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

Rapid increases in the costs of purchased gas would 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 enable us to serve any 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. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures during the next fiscal year in executing our steel service line replacement program in the Mid-Tex Division. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

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

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

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

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

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

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

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

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2011, our natural gas distribution segment owned an aggregate of 70,869 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 5,861 miles of gas transmission and gathering lines and our nonregulated segment owned 105 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 at September 30, 2011:

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	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	232,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated 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	60,458,299	30,549,198	91,007,497	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 at September 30, 2011:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment[2]			
	Colorado-Kansas Division	4,243,909	108,039
	Kentucky/Mid-States Division	16,835,380	444,339
	Louisiana Division	2,643,192	161,473
	Mississippi Division	3,875,429	165,402
	West Texas Division	2,375,000	81,000
Total		29,972,910	960,253
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		39,673,779	1,278,697

(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.

(2) On October 1, 2011, our Mid-Tex Division signed a new storage contract with a maximum storage quantity of 500,000 MMBtu and maximum daily withdrawal quantity of 50,000 MMBtu.

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. The headquarters for our nonregulated operations are 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.

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 2011 and 2010 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:

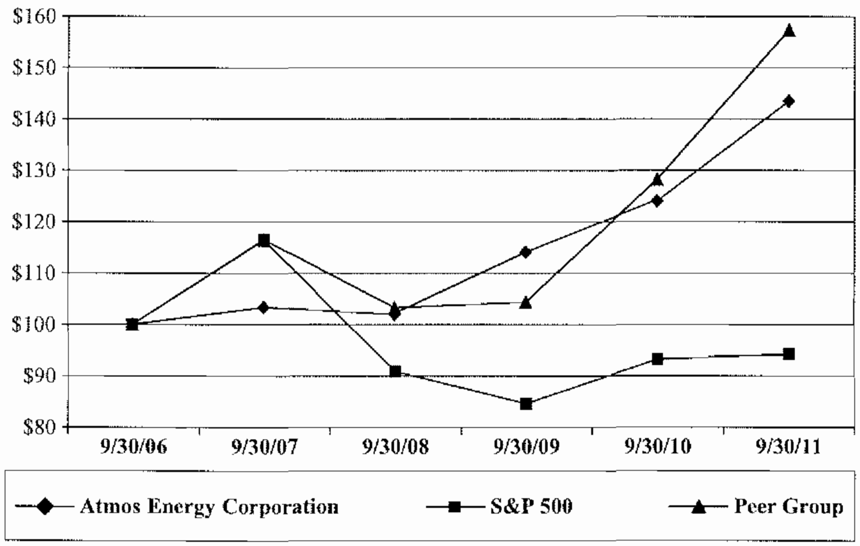
	Fiscal 2011			Fiscal 2010		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$31.72	$29.10	$.340	$30.06	$27.39	$.335
March 31	34.98	31.51	.340	29.52	26.52	.335
June 30	34.94	31.34	.340	29.98	26.41	.335
September 30	34.32	28.87	.340	29.81	26.82	.335
			$1.36			$1.34

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2011 was 18,746. 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 2011 that were not registered under the Securities Act of 1933, as amended.

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 natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2006 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 Indices



	Cumulative Total Return					
	9/30/06	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11
Atmos Energy Corporation	100.00	103.36	101.92	113.82	123.97	143.45
S&P 500	100.00	116.44	90.85	84.58	93.17	94.24
Peer Group	100.00	116.52	103.24	104.34	128.20	157.38

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, EQT Corporation, Integrys Energy Group, Inc., National Fuel Gas, Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Vectren Corporation and WGL Holdings, Inc.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2011.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan . .	86,766	$22.16	319,700
Total equity compensation plans approved by security holders. . .	86,766	22.16	319,700
Equity compensation plans not approved by security holders. . .	—	—	—
Total	86,766	$22.16	319,700

ITEM 6. *Selected Financial Data.*

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

	Fiscal Year Ended September 30				
	2011[1]	2010	2009[1]	2008	2007 [1]
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$4,347,634	$4,719,835	$4,869,111	$7,117,837	$5,803,177
Gross profit	1,327,241	1,337,505	1,319,678	1,293,922	1,221,078
Operating expenses[1]	885,342	860,354	883,312	878,399	835,353
Operating income	441,899	477,151	436,366	415,523	385,725
Miscellaneous income (expense)	21,499	(156)	(3,067)	3,017	9,227
Interest charges	150,825	154,360	152,638	137,218	145,019
Income from continuing operations before income taxes	312,573	322,635	280,661	281,322	249,933
Income tax expense	113,689	124,362	97,362	107,837	89,105
Income from continuing operations	198,884	198,273	183,299	173,485	160,828
Income from discontinued operations, net of tax	8,717	7,566	7,679	6,846	7,664
Net income	$ 207,601	$ 205,839	$ 190,978	$ 180,331	$ 168,492
Weighted average diluted shares outstanding	90,652	92,422	91,620	89,941	87,486
Income per share from continuing operations — diluted	$ 2.17	$ 2.12	$ 1.98	$ 1.91	$ 1.82
Income per share from discontinued operations — diluted	0.10	0.08	0.09	0.08	0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07	$ 1.99	$ 1.91
Cash flows from operations	$ 582,844	$ 726,476	$ 919,233	$ 370,933	$ 547,095
Cash dividends paid per share	$ 1.36	$ 1.34	$ 1.32	$ 1.30	$ 1.28
Natural gas distribution throughput from continuing operations (MMcf)[2]	409,369	438,535	393,604	413,491	411,337
Natural gas distribution throughput from discontinued operations (MMcf)[2]	14,651	15,640	15,281	15,863	16,532
Total regulated transmission and storage transportation volumes (MMcf)[2]	435,012	428,599	528,689	595,542	505,493
Total nonregulated delivered gas sales volumes (MMcf)[2]	384,799	353,853	370,569	389,392	370,668
Financial Condition					
Net property, plant and equipment[5]	$5,147,918	$4,793,075	$4,439,103	$4,136,859	$3,836,836
Working capital[6]	143,355	(290,887)	91,519	78,017	149,217
Total assets	7,282,871	6,763,791	6,367,083	6,386,699	5,895,197
Short-term debt, inclusive of current maturities of long-term debt	208,830	486,231	72,681	351,327	154,430
Capitalization:					
Shareholders' equity	2,255,421	2,178,348	2,176,761	2,052,492	1,965,754
Long-term debt (excluding current maturities)	2,206,117	1,809,551	2,169,400	2,119,792	2,126,315
Total capitalization	4,461,538	3,987,899	4,346,161	4,172,284	4,092,069
Capital expenditures	622,965	542,636	509,494	472,273	392,435
Financial Ratios					
Capitalization ratio[3]	48.3%	48.7%	49.3%	45.4%	46.3%
Return on average shareholders' equity[4]	9.1%	9.1%	8.9%	8.8%	8.8%

(1) Financial results for fiscal years 2011, 2009 and 2007 include a $30.3 million, $5.4 million and a $6.3 million pre-tax loss for the impairment of certain assets.

(2) Net of intersegment eliminations.

(3) 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.

(4) 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.

(5) Amount shown for fiscal 2011 are net of assets held for sale.

(6) Amount shown for fiscal 2011 includes assets held for sale.

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

INTRODUCTION

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

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

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

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, 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, fair value measurements, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee periodically. 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. We meet the criteria established within accounting principles generally accepted in the United States of a cost-based, rate-regulated entity, which requires us to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements in accordance with applicable authoritative accounting standards. We apply the provisions of this standard to our regulated operations and record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities 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 it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities 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 regulated operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

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

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities, which are subject to refund. 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 cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of cost, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility company's other costs, (ii) represents a large component of the utility company's cost of service and (iii) is generally outside the control of the gas utility company. There is no gross profit generated through purchased gas cost 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 cost adjustment mechanism. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

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

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments.

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

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

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk in this segment are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

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

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

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

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

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt with Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these Treasury lock agreements as cash flow hedges at the time the agreements are executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement is initially recorded as a component of accumulated other comprehensive income (loss) and is recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness, to the extent incurred, is reported as a component of interest expense.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. As of September 30, 2011, we had no indefinite-lived intangible assets.

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

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

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

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date 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. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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 and expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $1.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 million.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

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

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

RESULTS OF OPERATIONS

Overview

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

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

During fiscal 2011, we earned $207.6 million, or $2.27 per diluted share, which represents a one percent increase in net income and a three percent increase in diluted net income per share over fiscal 2010. During fiscal 2011, recent improvements in rate designs in our natural gas distribution segment and a successful regulatory outcome in our regulated transmission and storage segment offset a seven percent year-over-year decline in consolidated natural gas distribution throughput due to warmer weather and a 108 percent decrease in asset optimization margins as a result of weak natural gas market fundamentals. Results for fiscal 2011 were influenced by several non-recurring items, which increased diluted earnings per share by $0.03. The increase in fiscal 2011 earnings per share also reflects the favorable impact of our accelerated share buyback agreement initiated in the fourth quarter of fiscal 2010 and completed in the second quarter of fiscal 2011, which increased diluted earnings per share by $0.08.

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. Due to the pending sales transaction, the results of operations for these three service areas are shown in discontinued operations.

On June 10, 2011 we issued $400 million of 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks associated with the offering. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

During the year ended September 30, 2011, we executed on our strategy to streamline our credit facilities, as follows:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

After giving effect to these changes, we now have $985 million of liquidity available to us from our commercial paper program and four committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2011, 2010 and 2009.

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues	$4,347,634	$4,719,835	$4,869,111
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense)	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Diluted net income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Diluted net income per share from discontinued operations	$ 0.10	$ 0.08	$ 0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07

Historically, our regulated operations arising from our natural gas distribution and regulated transmission and storage operations contributed 65 to 85 percent of our consolidated net income. Regulated operations contributed 104 percent, 81 percent and 83 percent to our consolidated net income for fiscal years 2011, 2010, and 2009. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Natural gas distribution segment	$162,718	$125,949	$116,807
Regulated transmission and storage segment	52,415	41,486	41,056
Nonregulated segment	(7,532)	38,404	33,115
Net income	$207,601	$205,839	$190,978

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

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Regulated operations	$215,133	$167,435	$157,863
Nonregulated operations	(7,532)	38,404	33,115
Consolidated net income	$207,601	$205,839	$190,978
Diluted EPS from regulated operations	$ 2.35	$ 1.79	$ 1.71
Diluted EPS from nonregulated operations	(0.08)	0.41	0.36
Consolidated diluted EPS	$ 2.27	$ 2.20	$ 2.07

We reported net income of $207.6 million, or $2.27 per diluted share for the year ended September 30, 2011, compared with net income of $205.8 million or $2.20 per diluted share in the prior year. Income from continuing operations was $198.9 million, or $2.17 per diluted share compared with $198.3 million, or $2.12 per diluted share in the prior-year period. Income from discontinued operations was $8.7 million or $0.10 per diluted share for the year, compared with $7.6 million or $0.08 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year reduced net income by $6.6 million or $0.07 per diluted share compared with net losses recorded in the prior year of $4.3 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In the prior year, net income included the net positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. In the current year, net income includes the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

Net income during fiscal 2010 increased eight percent over fiscal 2009. Net income from our regulated operations increased six percent during fiscal 2010. The increase primarily reflects colder than normal weather in most of our service areas during fiscal 2010 as well as the net favorable impact of various ratemaking activities in our natural gas distribution segment. Net income in our nonregulated operations increased $5.3 million during fiscal 2010 primarily due to the impact of unrealized margins. Non-cash, net unrealized losses totaled $4.3 million which reduced earnings per share by $0.05 per diluted share in fiscal 2010 compared to fiscal 2009, when net unrealized losses totaled $21.6 million, which reduced earnings per share by $0.23 per diluted share.

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

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, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as 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.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 73 percent of our residential and commercial margins.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	**2010**	**2009**	**2011 vs. 2010**	**2010 vs. 2009**
	(In thousands, unless otherwise noted)				
Gross profit	$1,044,364	$1,022,011	$997,604	$ 22,353	$24,407
Operating expenses	706,363	711,842	719,626	(5,479)	(7,784)
Operating income	338,001	310,169	277,978	27,832	32,191
Miscellaneous income	16,557	1,567	6,002	14,990	(4,435)
Interest charges	115,802	118,319	123,863	(2,517)	(5,544)
Income from continuing operations before income taxes	238,756	193,417	160,117	45,339	33,300
Income tax expense	84,755	75,034	50,989	9,721	24,045
Income from continuing operations	154,001	118,383	109,128	35,618	9,255
Income from discontinued operations, net of tax	8,717	7,566	7,679	1,151	(113)
Net Income	$ 162,718	$ 125,949	$116,807	$ 36,769	$ 9,142
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	281,466	313,888	273,555	(32,422)	40,333
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	127,903	124,647	120,049	3,256	4,598
Consolidated natural gas distribution throughput from continuing operations — MMcf	409,369	438,535	393,604	(29,166)	44,931
Consolidated natural gas distribution throughput from discontinued operations — MMcf	14,651	15,640	15,281	(989)	359
Total consolidated natural gas distribution throughput — MMcf	424,020	454,175	408,885	(30,155)	45,290
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.47	$ 0.47	$ —	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ (0.47)	$ (1.18)

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the fiscal years ended September 30, 2011, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In thousands)		
Mid-Tex	$144,204	$134,655	$127,625	$ 9,549	$ 7,030
Kentucky/Mid-States	53,506	46,238	37,683	7,268	8,555
Louisiana	50,442	45,759	43,434	4,683	2,325
West Texas	29,686	33,509	23,338	(3,823)	10,171
Mississippi	26,338	26,441	21,287	(103)	5,154
Colorado-Kansas	25,920	24,543	20,580	1,377	3,963
Other	7,905	(976)	4,031	8,881	(5,007)
Total	$338,001	$310,169	$277,978	$27,832	$32,191

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

The $22.4 million increase in natural gas distribution gross profit primarily reflects a $40.4 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky and Kansas service areas.

These increases were partially offset by:

- $12.0 million decrease due to a seven percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.
- $8.1 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $5.5 million, primarily due to the following:

- $10.0 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.4 million decrease in employee-related expenses.

These decreases were partially offset by:

- $5.4 million increase due to the absence of a state sales tax reimbursement received in the prior year.
- $11.8 million increase in depreciation and amortization expense.
- $1.8 million increase in vehicles and equipment expense.

Net income for this segment for the year-to-date period was also favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $24.4 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $33.4 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana, Kentucky, Tennessee, Virginia and Mississippi service areas.

- $10.6 million increase as a result of an 11 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $7.6 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior-year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $1.6 million decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $7.8 million, primarily due to the following:

- $5.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $4.6 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in the prior year.
- $4.5 million decrease in contract labor expenses.
- $4.6 million decrease in travel, legal and other administrative costs.

These decreases were partially offset by:

- $7.5 million increase in employee-related expenses.
- $4.5 million increase in taxes, other than income.

Miscellaneous income decreased $4.4 million due to lower interest income. Interest charges decreased $5.5 million primarily due to lower short-term debt balances and interest rates.

Additionally, results for the fiscal year ended September 30, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. During the second quarter of fiscal 2009, the Company completed a study of the calculations used to estimate its deferred tax rate, and concluded that revisions to these calculations to include more specific jurisdictional tax rates would result in a more accurate calculation of the tax rate at which deferred taxes would reverse in the future. Accordingly, the Company modified the tax rate used to calculate deferred taxes from 38 percent to an individual rate for each legal entity. These rates vary from 36-41 percent depending on the jurisdiction of the legal entity.

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 excess gas.

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 Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2011, 2010, and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	**2010**	**2009**	**2011 vs. 2010**	**2010 vs. 2009**
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$125,973	$102,891	$ 89,348	$ 23,082	$ 13,543
Third-party transportation	73,676	73,648	95,314	28	(21,666)
Storage and park and lend services	7,995	10,657	11,858	(2,662)	(1,201)
Other	11,729	15,817	13,138	(4,088)	2,679
Gross profit	219,373	203,013	209,658	16,360	(6,645)
Operating expenses	111,098	105,975	116,495	5,123	(10,520)
Operating income	108,275	97,038	93,163	11,237	3,875
Miscellaneous income	4,715	135	1,433	4,580	(1,298)
Interest charges	31,432	31,174	30,982	258	192
Income before income taxes	81,558	65,999	63,614	15,559	2,385
Income tax expense	29,143	24,513	22,558	4,630	1,955
Net income	$ 52,415	$ 41,486	$ 41,056	$ 10,929	$ 430
Gross pipeline transportation volumes — MMcf	620,904	634,885	706,132	(13,981)	(71,247)
Consolidated pipeline transportation volumes — MMcf	435,012	428,599	528,689	6,413	(100,090)

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

On April 18, 2011, the Railroad Commission of Texas (RRC) issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $16.4 million increase in regulated transmission and storage gross profit was attributable primarily to the following:

- $23.4 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $3.2 million increase associated with our most recent GRIP filing.

These increases were partially offset by the following:

- $4.8 million decrease due to the absence of the sale of excess gas, which occurred in the prior year.
- $4.4 million decrease due to a decline in throughput to our Mid-Tex Division primarily due to warmer than normal weather during fiscal 2011.

Operating expenses increased $5.1 million primarily due to the following:

- $4.6 million increase due to higher depreciation expense.
- $2.0 million increase due to the absence of a state sales tax reimbursement received in the prior year.

These increases were partially offset by the following:

- $0.8 million decrease related to lower levels of pipeline maintenance activities.
- $0.7 million decrease due to lower employee-related expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $6.6 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.3 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $2.6 million decrease due to decreased through-system volumes primarily associated with market conditions that resulted in reduced wellhead production, decreased drilling activity and increased competition, partially offset by increased deliveries to our Mid-Tex Division.
- $1.6 million net decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.

These decreases were partially offset by the following:

- $9.3 million increase associated with our GRIP filings.
- $2.0 million increase of excess inventory sales in the current-year period.

Operating expenses decreased $10.5 million primarily due to:

- $11.8 million decrease related to reduced contract labor.
- $2.0 million decrease due to a state sales tax reimbursement received in March 2010.

These decreases were partially offset by a $2.1 million increase in taxes, other than income due to higher ad valorem and payroll taxes.

Miscellaneous income decreased $1.3 million due primarily to a decline in intercompany interest income.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to offset the original financial instruments. If AEH elects to defer the withdrawal of gas, it will execute new financial instruments to correspond to the revised withdrawal schedule and allow the original financial instrument to settle as contracted.

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

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

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

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

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

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

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$ 58,990	$ 59,523	$ 75,341	$ (533)	$(15,818)
Storage and transportation services	14,570	13,206	12,784	1,364	422
Other	5,265	5,347	9,365	(82)	(4,018)
	78,825	78,076	97,490	749	(19,414)
Asset optimization[1]	(3,424)	43,805	52,507	(47,229)	(8,702)
Total realized margins	75,401	121,881	149,997	(46,480)	(28,116)
Unrealized margins	(10,401)	(7,790)	(35,889)	(2,611)	28,099
Gross profit	65,000	114,091	114,108	(49,091)	(17)
Operating expenses, excluding asset impairment	39,113	44,147	49,046	(5,034)	(4,899)
Asset impairment	30,270	—	181	30,270	(181)
Operating income (loss)	(4,383)	69,944	64,881	(74,327)	5,063
Miscellaneous income	657	3,859	6,399	(3,202)	(2,540)
Interest charges	4,015	10,584	14,350	(6,569)	(3,766)
Income (loss) before income taxes	(7,741)	63,219	56,930	(70,960)	6,289
Income tax expense (benefit)	(209)	24,815	23,815	(25,024)	1,000
Net income (loss)	$ (7,532)	$ 38,404	$ 33,115	$(45,936)	$ 5,289
Gross nonregulated delivered gas sales volumes — MMcf	446,903	420,203	441,081	26,700	(20,878)
Consolidated nonregulated delivered gas sales volumes — MMcf	384,799	353,853	370,569	30,946	(16,716)
Net physical position (Bcf)	21.0	15.7	15.9	5.3	(0.2)

[1] Net of storage fees of $15.2 million, $13.2 million and $10.8 million.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

Realized margins for gas delivery, storage and transportation services and other services were $78.8 million during the year ended September 30, 2011 compared with $78.1 million for the prior-year period. The increase primarily reflects the following:

- $1.4 million increase in margins from storage and transportation services, primarily attributable to new drilling projects in the Barnett Shale area.

- $0.6 million decrease in gas delivery and other services primarily due to lower per-unit margins partially offset by a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market. Per-unit margins were $0.13/Mcf in the current year compared with $0.14/Mcf in the prior year. The year-over-year decrease in per-unit margins reflects the impact of increased competition and lower basis spreads.

The $47.2 million decrease in realized asset optimization margins from the prior year primarily reflects the unfavorable impact of weak natural gas market fundamentals which provided fewer favorable trading opportunities.

Unrealized margins decreased $2.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.0 million primarily due to lower employee-related expenses and ad valorem taxes.

During fiscal 2011, our nonregulated segment recognized $30.3 million of non-cash asset impairment charges associated with two projects. In March 2011, we recorded a $19.3 million charge to substantially write off our investment in Fort Necessity. This project began in February 2008 when Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. At that time, we evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Additionally, during the third quarter of fiscal 2011, we recorded an $11.0 million non-cash charge to impair certain natural gas gathering assets of Atmos Gathering Company. The charge reflected a reduction in the value of the project due to the current low natural gas price environment and the adverse impact of an ongoing lawsuit associated with the project.

Interest charges decreased $6.6 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at September 30, 2011 and 2010.

	September 30	
	2011	2010
	(In millions, unless otherwise noted)	
Economic value	$ 4.9	$ (7.5)
Associated unrealized losses	14.7	12.8
Subtotal	19.6	5.3
Related fees[1]	(17.7)	(10.6)
Potential gross profit (loss)	$ 1.9	$ (5.3)
Net physical position (Bcf)	21.0	15.7

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of September 30, 2011 and 2010.

During the 2011 fiscal year, our nonregulated segment's economic value increased from a negative economic value of ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to $4.9 million, or $0.23/Mcf at September 30, 2011.

The increase in economic value was attributable to several factors including an increase in the captured spread value resulting from realizing financial instruments with lower spread values, entering into financial hedges with higher average prices and rolling financial instruments to forward periods to capture incremental value. Additionally, as a result of falling gas prices throughout the year, we injected a net 5.3 Bcf, which reduced the overall weighted average cost of gas held in storage.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit as of September 30, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

Realized margins for gas delivery, storage and transportation services and other services contributed 64 percent to total realized margins during fiscal 2010, with asset optimization activities contributing the remaining 36 percent. In fiscal 2009, gas delivery, storage and transportation services and other services represented 65 percent of the nonregulated segment's realized margins with asset optimization contributing the remaining 35 percent. The $28.1 million decrease in realized gross profit reflected:

- $19.4 million decrease in gas delivery, storage and transportation services and other services as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit delivered gas margins were $0.14/Mcf in fiscal 2010, compared with $0.17/Mcf in fiscal 2009, while delivered gas volumes were 5 percent lower in fiscal 2010 when compared with fiscal 2009.
- $8.7 million decrease in asset optimization due to lower margins earned on storage optimization activities, lower basis gains earned from utilizing leased capacity and lower margins earned on asset management plans, partially offset by higher realized storage and trading gains during fiscal 2010.

The decrease in realized gross profit was offset by a $28.1 million increase in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments decreased $5.1 million primarily due a decrease in employee and other administrative costs, partially offset by an increase in gas gathering activities.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we executed on our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit, including the following:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased during fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

As a result of these changes, we now have $985 million of availability from our commercial paper program and four committed revolving credit facilities with third parties.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011 using commercial paper borrowings. In effect, we refinanced this debt on a long-term basis through the issuance of $400 million 5.50% 30-year unsecured senior notes on June 10, 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury lock and settlement. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

Finally, we intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2012.

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 such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 582,844	$ 726,476	$ 919,233	$(143,632)	$(192,757)
Investing activities	(627,386)	(542,702)	(517,201)	(84,684)	(25,501)
Financing activities	44,009	(163,025)	(337,546)	207,034	174,521
Change in cash and cash equivalents	(533)	20,749	64,486	(21,282)	(43,737)
Cash and cash equivalents at beginning of period	131,952	111,203	46,717	20,749	64,486
Cash and cash equivalents at end of period	$ 131,419	$ 131,952	$ 111,203	$ (533)	$ 20,749

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Fiscal Year ended September 30, 2011 compared with fiscal year ended September 30, 2010

For the fiscal year ended September 30, 2011, we generated operating cash flow of $582.8 million from operating activities compared with $726.5 million in the prior year. The year-over-year decrease reflects the absence of an $85 million income tax refund received in the prior year coupled with the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Fiscal Year ended September 30, 2010 compared with fiscal year ended September 30, 2009

For the fiscal year ended September 30, 2010, we generated operating cash flow of $726.5 million from operating activities compared with $919.2 million in fiscal 2009, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flows for the fiscal 2010 period reflect the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flows were favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable 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 focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. 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.

In early fiscal 2010, two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, agreed to a program of installing, beginning in the first quarter of fiscal 2011, 100,000 steel service line replacements during fiscal 2011 and 2012, with approved recovery of the associated return, depreciation and taxes. During fiscal 2011, we replaced 35,852 lines for a cost of $49.7 million. The program is progressing on schedule for completion in September 2012. As a result of this project and spending to replace our regulated customer service systems and our nonregulated energy trading risk management system, we anticipate capital expenditures will remain elevated during the next fiscal year.

For the fiscal year ended September 30, 2011, we incurred $623.0 million for capital expenditures compared with $542.6 million for the fiscal year ended September 30, 2010 and $509.5 million for the fiscal year ended September 30, 2009.

The $80.4 million increase in capital expenditures in fiscal 2011 compared to fiscal 2010 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and the construction of a new customer contact center in Amarillo, Texas, partially offset by costs incurred in the prior fiscal year to relocate the company's information technology data center.

The $33.1 million increase in capital expenditures in fiscal 2010 compared to fiscal 2009 primarily reflects spending for the relocation of our information technology data center to a new facility, the construction of two service centers and the steel service line replacement program in our Mid-Tex Division.

Cash flows from financing activities

For the fiscal year ended September 30, 2011, our financing activities generated $44.0 million in cash, while financing activities for the fiscal year ended September 30, 2010 used $163.0 million in cash compared with cash of $337.5 million used for the fiscal year ended September 30, 2009. Our significant financing activities for the fiscal years ended September 30, 2011, 2010 and 2009 are summarized as follows:

2011

During the fiscal year ended September 30, 2011, we:

- Received $394.5 million net cash proceeds in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- Borrowed a net $83.3 million under our short-term facilities to fund working capital needs.
- Received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.
- Received $20.1 million cash in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- Received $7.8 million net proceeds related to the issuance of 0.3 million shares of common stock.

- Paid $360.1 million for scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011.
- Paid $124.0 million in cash dividends which reflected a payout ratio of 60 percent of net income.
- Paid $5.3 million for the repurchase of equity awards.

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under an accelerated share repurchase agreement.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that beginning in fiscal 2010 shares were purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

2009

During the fiscal year ended September 30, 2009, we:

- Paid $407.4 million to repay our $400 million 4.00% unsecured notes.
- Repaid a net $284.0 million short-term borrowings under our credit facilities.
- Paid $121.5 million in cash dividends which reflected a payout ratio of 64 percent of net income.
- Received $445.6 million in net proceeds related to the March 2009 issuance of $450 million of 8.50% Senior Notes due 2019. The net proceeds were used to repay the $400 million 4.00% unsecured notes.
- Received $27.7 million net proceeds related to the issuance of 1.2 million shares of common stock.
- Received $1.9 million net proceeds related to the settlement of the Treasury lock agreement associated with the March 2009 issuance of the $450 million of 8.50% Senior Notes due 2019.

The following table shows the number of shares issued for the fiscal years ended September 30, 2011, 2010 and 2009:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
Shares issued:			
Direct stock purchase plan	—	103,529	407,262
Retirement savings plan	—	79,722	640,639
1998 Long-term incentive plan	675,255	421,706	686,046
Outside directors stock-for-fee plan	2,385	3,382	3,079
Total shares issued	677,640	608,339	1,737,026

The number of shares issued in fiscal 2011 compared with the number of shares issued in fiscal 2010 primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current fiscal year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During fiscal 2011, we cancelled and retired 169,793 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

The year-over-year decrease in the number of shares issued in fiscal 2010 compared with the number of shares issued in fiscal 2009, primarily reflects the fact that in fiscal 2010, we began to purchase shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. Further, a higher average stock price during the second and third quarters of fiscal 2010 compared to the second and third quarters of 2009 enabled us to issue fewer shares during fiscal 2010. Additionally, during fiscal 2010, we cancelled and retired 37,365 shares attributable to federal withholdings on equity awards and repurchased and retired 2,958,580 common shares as part of our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings typically reach their highest levels in the winter months.

As of September 30, 2011, we financed our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided $985 million of working capital funding. As of September 30, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $702.5 million. These facilities are described in further detail in Note 7 to the consolidated financial statements.

On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.

In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At September 30, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

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 environment in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). On May 11, 2011, Moody's upgraded our senior unsecured debt rating to Baa1 from Baa2, with a ratings outlook of stable, citing steady rate increases, improving credit metrics and a strategic focus on lower risk regulated activities as reasons for the upgrade. On June 2, 2011, Fitch upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing a constructive regulatory environment, strategic focus on lower risk regulated activities and the geographic diversity of our regulated operations as key rating factors. As of September 30, 2011, S&P maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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, 2011. Our debt covenants are described in Note 7 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2011 and 2010:

	September 30			
	2011		2010	
	(In thousands, except percentages)			
Short-term debt	$ 206,396	4.4%	$ 126,100	2.8%
Long-term debt	2,208,551	47.3%	2,169,682	48.5%
Shareholders' equity	2,255,421	48.3%	2,178,348	48.7%
Total capitalization, including short-term debt	$4,670,368	100.0%	$4,474,130	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.7 percent and 51.3 percent at September 30, 2011 and 2010. The increase in the debt to capitalization ratio primarily reflects an increase in short-term debt as of September 30, 2011 compared to the prior year. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to continue to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2011.

	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)	$2,212,565	$ 2,434	$250,131	$500,000	$1,460,000
Short-term debt(1)	206,396	206,396	—	—	—
Interest charges(2)	1,574,702	136,452	250,841	198,596	988,813
Gas purchase commitments(3)	460,179	274,985	185,194	—	—
Capital lease obligations(4)	1,194	186	372	372	264
Operating leases(4)	199,567	17,718	33,365	30,376	118,108
Demand fees for contracted storage(5)	19,339	11,421	6,770	983	165
Demand fees for contracted transportation(6)	37,295	13,941	19,929	3,425	—
Financial instrument obligations(7)	93,542	15,453	78,089	—	—
Postretirement benefit plan contributions(8)	194,323	31,519	28,543	35,122	99,139
Total contractual obligations	$4,999,102	$710,505	$853,234	$768,874	$2,666,489

(1) See Note 7 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, 2011.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our nonregulated segment. 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 nonregulated segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2011. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled. The table above excludes $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

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

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.49 to $6.36 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 terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of natural 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, 2011 are reflected in the table above.

Risk Management Activities

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

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

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(49,600)
Contracts realized/settled	(51,136)
Fair value of new contracts	2,584
Other changes in value	18,875
Fair value of contracts at September 30, 2011	$(79,277)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2011, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2011				
	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	$(12,413)	$(66,864)	$—	$—	$(79,277)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(12,413)	$(66,864)	$—	$—	$(79,277)

The tables above include $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the fiscal year ended September 30, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(12,374)
Contracts realized/settled	4,017
Fair value of new contracts	—
Other changes in value	(16,693)
Fair value of contracts at September 30, 2011	(25,050)
Netting of cash collateral	28,787
Cash collateral and fair value of contracts at September 30, 2011	$ 3,737

The fair value of our nonregulated segment's financial instruments at September 30, 2011, is presented below by time period and fair value source.

	Fair Value of Contracts at September 30, 2011				
	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	$(14,823)	$(10,050)	$(177)	$—	$(25,050)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(14,823)	$(10,050)	$(177)	$—	$(25,050)

Employee Benefit Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefit programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2005, we have experienced medical and prescription inflation of approximately seven percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. Although we are still assessing the impact of the Health Care Reform Act on the health care benefits we provide to our employees, the design of our health care plans has already changed in order to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in fiscal 2012. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2012, we anticipate an approximate 10 percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the implementation of the Health Care Reform Act.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2011, our total net periodic pension and other benefits costs was \$56.6 million, compared with \$50.8 million and \$50.2 million for the fiscal years ended September 30, 2010 and 2009. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. Our expected return on our pension plan assets remained constant at 8.25 percent. Accordingly, our fiscal 2011 pension and postretirement medical costs were higher than in the prior year.

The increase in total net periodic pension and other benefits costs during fiscal 2010 compared with fiscal 2009 primarily reflects the decline in fair value of our plan assets. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2009 measurement date, the interest rates were slightly lower than the interest rates at September 30, 2008, the measurement date used to determine our fiscal 2009 net periodic cost. Our expected return on our pension plan assets remained constant at 8.25 percent.

Pension and Postretirement Plan Funding

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

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based on this valuation, we were required to contribute cash of $0.9 million to our pension plans during fiscal 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold.

During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the PPA. During fiscal 2009, we contributed $21.0 million to our pension plans to achieve the same desired level of funding as established by the PPA.

We contributed $11.3 million, $11.8 million and $10.1 million to our postretirement benefits plans for the fiscal years ended September 30, 2011, 2010 and 2009. 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 2012 and Beyond

As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2012 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is partially mitigated by the fact that assets are smoothed for purposes of determining net periodic pension cost which results in asset gains and losses that are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Due to the decrease in our discount rate and our expected return on plan assets as well as the decline in the fair value of our plan assets, we expect our fiscal 2012 pension and postretirement medical costs to increase compared to fiscal 2011.

Based upon market conditions subsequent to September 30, 2011 the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing approximately $32 million during fiscal 2012.

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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

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 nonregulated 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 nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 4 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

Natural gas distribution segment

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

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated 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, 2011 of 0.1 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, 2011 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 $6.7 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 $1.2 million during 2011.

ITEM 8. ***Financial Statements and Supplementary Data.***

Index to financial statements and financial statement schedule:

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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

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2011 and 2010, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, 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), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, 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 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30	
	2011	2010
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,607,552	$6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less accumulated depreciation and amortization	1,668,876	1,749,243
Net property, plant and equipment	5,147,918	4,793,075
Current assets		
Cash and cash equivalents	131,419	131,952
Accounts receivable, less allowance for doubtful accounts of $7,440 in 2011 and $12,701 in 2010	273,303	273,207
Gas stored underground	289,760	319,038
Other current assets	316,471	150,995
Total current assets	1,010,953	875,192
Goodwill and intangible assets	740,207	740,148
Deferred charges and other assets	383,793	355,376
	$7,282,871	$6,763,791
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2011 — 90,296,482 shares, 2010 — 90,164,103 shares	$ 451	$ 451
Additional paid-in capital	1,732,935	1,714,364
Accumulated other comprehensive loss	(48,460)	(23,372)
Retained earnings	570,495	486,905
Shareholders' equity	2,255,421	2,178,348
Long-term debt	2,206,117	1,809,551
Total capitalization	4,461,538	3,987,899
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	291,205	266,208
Other current liabilities	367,563	413,640
Short-term debt	206,396	126,100
Current maturities of long-term debt	2,434	360,131
Total current liabilities	867,598	1,166,079
Deferred income taxes	960,093	829,128
Regulatory cost of removal obligation	428,947	350,521
Deferred credits and other liabilities	564,695	430,164
	$7,282,871	$6,763,791

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,531,863	$2,842,638	$2,884,796
Regulated transmission and storage segment	219,373	203,013	209,658
Nonregulated segment	2,024,893	2,146,658	2,283,988
Intersegment eliminations	(428,495)	(472,474)	(509,331)
	4,347,634	4,719,835	4,869,111
Purchased gas cost			
Natural gas distribution segment	1,487,499	1,820,627	1,887,192
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,959,893	2,032,567	2,169,880
Intersegment eliminations	(426,999)	(470,864)	(507,639)
	3,020,393	3,382,330	3,549,433
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses			
Operation and maintenance	449,290	460,513	485,704
Depreciation and amortization	227,099	211,589	211,984
Taxes, other than income	178,683	188,252	180,242
Asset impairments	30,270	—	5,382
Total operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense), net	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax ($5,502, $4,425 and $2,929)	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Basic earnings per share			
Income per share from continuing operations	$ 2.18	$ 2.14	$ 1.99
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — basic	$ 2.28	$ 2.22	$ 2.08
Diluted earnings per share			
Income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — diluted	$ 2.27	$ 2.20	$ 2.07
Weighted average shares outstanding:			
Basic	90,201	91,852	91,117
Diluted	90,652	92,422	91,620

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock		Additional	Accumulated Other		
	Number of Shares	Stated Value	Paid-in Capital	Comprehensive Loss	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2008	90,814,683	$454	$1,744,384	$(35,947)	$ 343,601	$2,052,492
Comprehensive income:						
Net income	—	—	—	—	190,978	190,978
Unrealized holding losses on investments, net	—	—	—	(1,820)	—	(1,820)
Other than temporary impairment of investments, net	—	—	—	3,370	—	3,370
Treasury lock agreements, net	—	—	—	3,606	—	3,606
Cash flow hedges, net	—	—	—	10,607	—	10,607
Total comprehensive income						206,741
Change in measurement date for employee benefit plans	—	—	—	—	(7,766)	(7,766)
Cash dividends ($1.32 per share)	—	—	—	—	(121,460)	(121,460)
Common stock issued:						
Direct stock purchase plan	407,262	2	8,743	—	—	8,745
Retirement savings plan	640,639	3	16,571	—	—	16,574
1998 Long-term incentive plan	686,046	4	8,075	—	—	8,079
Employee stock-based compensation	—	—	13,280	—	—	13,280
Outside directors stock-for-fee plan	3,079	—	76	—	—	76
Balance, September 30, 2009	92,551,709	463	1,791,129	(20,184)	405,353	2,176,761
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net	—	—	—	1,745	—	1,745
Treasury lock agreements, net	—	—	—	2,030	—	2,030
Cash flow hedges, net	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income	—	—	—	—	207,601	207,601
Unrealized holding losses on investments, net	—	—	—	(1,647)	—	(1,647)
Treasury lock agreements, net	—	—	—	(28,689)	—	(28,689)
Cash flow hedges, net	—	—	—	5,248	—	5,248
Total comprehensive income						182,513
Repurchase of common stock	(375,468)	(2)	2	—	—	—
Repurchase of equity awards	(169,793)	(1)	(5,298)	—	—	(5,299)
Cash dividends ($1.36 per share)	—	—	—	—	(124,011)	(124,011)
Common stock issued:						
Direct stock purchase plan	—	—	(54)	—	—	(54)
1998 Long-term incentive plan	675,255	3	13,886	—	—	13,889
Employee stock-based compensation	—	—	9,958	—	—	9,958
Outside directors stock-for-fee plan	2,385	—	77	—	—	77
Balance, September 30, 2011	90,296,482	$451	$1,732,935	$(48,460)	$ 570,495	$2,255,421

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 207,601	$ 205,839	$ 190,978
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	30,270	—	5,382
Depreciation and amortization:			
Charged to depreciation and amortization	233,155	216,960	217,208
Charged to other accounts	228	173	94
Deferred income taxes	117,353	196,731	129,759
Stock-based compensation	11,586	12,655	14,494
Debt financing costs	9,438	11,908	10,364
Other	(961)	(1,245)	(1,177)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(96)	(40,401)	244,713
Decrease in gas stored underground	27,737	54,014	194,287
(Increase) decrease in other current assets	(38,048)	(18,387)	117,737
(Increase) decrease in deferred charges and other assets	(53,519)	14,886	(106,231)
Increase (decrease) in accounts payable and accrued liabilities	23,904	58,069	(181,978)
Decrease in other current liabilities	(57,495)	(48,992)	(717)
Increase in deferred credits and other liabilities	71,691	64,266	84,320
Net cash provided by operating activities	582,844	726,476	919,233
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(622,965)	(542,636)	(509,494)
Other, net	(4,421)	(66)	(7,707)
Net cash used in investing activities	(627,386)	(542,702)	(517,201)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	83,306	54,268	(283,981)
Net proceeds from issuance of long-term debt	394,466	—	445,623
Settlement of Treasury lock agreements	20,079	—	1,938
Unwinding of Treasury lock agreements	27,803	—	—
Repayment of long-term debt	(360,131)	(131)	(407,353)
Cash dividends paid	(124,011)	(124,287)	(121,460)
Repurchase of common stock	—	(100,450)	—
Repurchase of equity awards	(5,299)	(1,191)	—
Issuance of common stock	7,796	8,766	27,687
Net cash provided by (used in) financing activities	44,009	(163,025)	(337,546)
Net increase (decrease) in cash and cash equivalents	(533)	20,749	64,486
Cash and cash equivalents at beginning of year	131,952	111,203	46,717
Cash and cash equivalents at end of year	$ 131,419	$ 131,952	$ 111,203

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

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

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

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

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

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. The results of these operations have been separately reported as discontinued operations.

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

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

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; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements 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. Accounting principles generally accepted in the United States require 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.

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, 2011 and 2010 included the following:

	September 30	
	2011	2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$254,666	$209,564
Merger and integration costs, net	6,242	6,714
Deferred gas costs	33,976	22,701
Regulatory cost of removal asset	8,852	31,014
Environmental costs	385	805
Rate case costs	4,862	4,505
Deferred franchise fees	379	1,161
Other	3,534	1,046
	$312,896	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 8,130	$ 43,333
Regulatory cost of removal obligation	464,025	381,474
Other	14,025	6,112
	$486,180	$430,919

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2011, 2010 and 2009, we recognized $0.5 million, $0.4 million and $0.4 million in amortization expense related to these costs.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. During the year ended September 30, 2009 we recognized a non-recurring $7.6 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, 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 cost adjustment mechanisms. Purchased gas cost 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 cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our nonregulated activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2011, 2010 and 2009, we included unrealized gains (losses) on open contracts of \$(10.4) million, \$(7.8) million and \$(35.9) million as a component of nonregulated revenues.

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

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

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

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our nonregulated segment to conduct their operations. The average cost method is used for all our regulated operations, 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. Our nonregulated segment utilizes the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of \$1.7 million, \$3.9 million and \$4.9 million was capitalized in 2011, 2010 and 2009.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.6 percent, 3.5 percent and 3.8 percent for the fiscal years ended September 30, 2011, 2010 and 2009.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 50 years.

Asset retirement obligations — 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, 2011 and 2010, we recorded asset retirement obligations of $14.0 million and $11.4 million. Additionally, we recorded $5.4 million and $3.8 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 natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot 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 2011, we recorded pretax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering system, as discussed in Note 5.

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

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

Marketable securities — As of September 30, 2011 and 2010, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, 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.

Due to the deterioration of the financial markets in late calendar 2008 and early calendar 2009 and the uncertainty of a full recovery of these investments given the then current economic environment, we recorded a $5.4 million noncash charge to impair certain available-for-sale investments during fiscal 2009.

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

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

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

Financial Instruments Associated with Commodity Price Risk

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

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

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

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

In our nonregulated segment, we also utilize master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2011 and 2010, the Company netted \$28.8 million and \$24.9 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. In fiscal 2011 and in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Our Master Trust has investments in real estate that qualify as Level 3 fair value measurements. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. To comply with the new measurement date requirements established by the Financial Accounting Standards Board (FASB) and incorporated into accounting principles generally accepted in the United States, effective October 1, 2008, we changed our measurement date from June 30 to our fiscal year end, September 30. This change is more fully discussed in Note 9. 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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan which was enhanced, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

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 bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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

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

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

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

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2011 and 2010, consisted of the following unrealized gains (losses):

	September 30	
	2011	2010
	(In thousands)	
Unrealized holding gains on investments	$ 2,558	$ 4,205
Treasury lock agreements	(34,157)	(5,468)
Cash flow hedges	(16,861)	(22,109)
	$(48,460)	$(23,372)

Subsequent events — We have evaluated subsequent events from the September 30, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. No events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — During the year ended September 30, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards had no impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2011.

For interim and annual periods beginning after December 15, 2011, three new accounting pronouncements will become applicable to the Company including guidance that will change certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements, guidance related to the presentation of other comprehensive income which will require that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements and new guidance related to goodwill impairment testing that will permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the traditional two-step goodwill impairment test. The adoption of these standards should not impact our financial position, results of operations or cash flows.

3. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2011 and 2010:

	September 30 2011	September 30 2010
	(In thousands)	
Goodwill	$740,000	$739,314
Intangible assets	207	834
Total	$740,207	$740,148

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2011:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
		(In thousands)		
Balance as of September 30, 2010	$572,262	$132,341	$34,711	$739,314
Deferred tax adjustments on prior acquisitions[1]	646	40	—	686
Balance as of September 30, 2011	$572,908	$132,381	$34,711	$740,000

[1] During the preparation of the fiscal 2011 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $0.7 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2011 and 2010, we had no intangible assets with indefinite lives.

	Useful Life (Years)	September 30, 2011 Gross Carrying Amount	September 30, 2011 Accumulated Amortization	September 30, 2011 Net	September 30, 2010 Gross Carrying Amount	September 30, 2010 Accumulated Amortization	September 30, 2010 Net
			(In thousands)				
Customer contracts	10	$6,926	$(6,719)	$207	$6,926	$(6,092)	$834

The following table presents actual amortization expense recognized during 2011 and an estimate of future amortization expense based upon our intangible assets at September 30, 2011.

Amortization expense (in thousands):

Actual for the fiscal year ending September 30, 2011	$627
Estimated for the fiscal year ending:	
September 30, 2012	$ 43
September 30, 2013	43
September 30, 2014	43
September 30, 2015	43
September 30, 2016	35

4. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2011 and 2010:

	Natural Gas Distribution	Nonregulated	Total
		(In thousands)	
September 30, 2011[3]			
Assets from risk management activities, current[1]	$ 843	$ 17,501	$ 18,344
Assets from risk management activities, noncurrent	998	—	998
Liabilities from risk management activities, current[1]	(11,916)	(3,537)	(15,453)
Liabilities from risk management activities, noncurrent	(67,862)	(10,227)	(78,089)
Net assets (liabilities)	$(77,937)	$ 3,737	$(74,200)
September 30, 2010			
Assets from risk management activities, current[2]	$ 2,219	$ 18,356	$ 20,575
Assets from risk management activities, noncurrent	47	890	937
Liabilities from risk management activities, current[2]	(48,942)	(731)	(49,673)
Liabilities from risk management activities, noncurrent	(2,924)	(6,000)	(8,924)
Net assets (liabilities)	$(49,600)	$ 12,515	$(37,085)

(1) Includes $28.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

(2) Includes $24.9 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

(3) The September 30, 2011 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations. At September 30, 2011, assets and liabilities held for sale included $1.3 million of current liabilities from risk management activities.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $5.81 per Mcf. We have not designated these financial instruments as hedges.

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

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers' request.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 62 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

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

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. This offering is discussed in Note 7. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter of fiscal 2011.

In prior years, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extends through fiscal 2041.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and income statements.

As of September 30, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(13,950)
	Cash Flow	—	38,713
	Not designated	26,977	31,648
		26,977	56,411

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of September 30, 2011 and 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $28.8 million and $24.9 million of cash held on deposit in margin accounts as of September 30, 2011 and 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

to the amounts presented on our consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts . .	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts . .	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts . .	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts . .	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2011, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.8 million, $51.8 million and $6.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2011, 2010 and 2009 is presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Commodity contracts	$16,552	$34,650	$ 45,120
Fair value adjustment for natural gas inventory designated as the hedged item	9,824	19,867	(28,831)
Total impact on revenue	$26,376	$54,517	$ 16,289
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 803	$ (1,272)	$ 5,958
Timing ineffectiveness	25,573	55,789	10,331
	$26,376	$54,517	$ 16,289

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2011, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
		(In thousands)		
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(28,430)	$(28,430)
Loss arising from ineffective portion of commodity contracts	—	—	(1,585)	(1,585)
Total impact on revenue	—	—	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total impact from cash flow hedges	$19,348	$6,000	$(30,015)	$ (4,667)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(44,809)	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	—	(2,717)	(2,717)
Total impact on revenue	—	—	(47,526)	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$ —	$(47,526)	$(50,204)

	Fiscal Year Ended September 30, 2009			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(136,540)	$(136,540)
Loss arising from ineffective portion of commodity contracts	—	—	(9,888)	(9,888)
Total impact on revenue	—	—	(146,428)	(146,428)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(4,070)	—	—	(4,070)
Total impact from cash flow hedges	$(4,070)	$ —	$(146,428)	$(150,498)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Fiscal Year Ended September 30	
	2011	2010
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$(12,720)	$ 343
Forward commodity contracts	(12,096)	(34,296)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	(15,969)	1,687
Forward commodity contracts	17,344	27,333
Total other comprehensive loss from hedging, net of tax(1)	$(23,441)	$ (4,933)

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2011. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into in August 2011 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2012	$(1,266)	$(12,160)	$(13,426)
2013	(1,266)	(3,214)	(4,480)
2014	(1,266)	(1,461)	(2,727)
2015	601	(29)	572
2016	770	3	773
Thereafter	10,812	—	10,812
Total[1]	$ 8,385	$(16,861)	$ (8,476)

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2011, 2010 and 2009 was an increase (decrease) in revenue of $(1.4) million, $15.4 million and $36.9 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 9 below.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and 2010. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment	15,262	97,396	—	(95,156)	17,502
Total financial instruments	15,262	99,237	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$99,646	$115,426	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment	22,091	115,617	—	(123,943)	13,765
Total liabilities	$22,091	$196,735	$ —	$(123,943)	$ 94,883

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities					
Money market funds	—	499	—	—	499
Registered investment companies	40,967	—	—	—	40,967
Total available-for-sale securities	40,967	499	—	—	41,466
Total assets	$117,018	$45,227	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.4 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting agreements and the remaining $12.3 million is classified as current risk management assets.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

At September 30, 2011 and 2010, our available-for-sale securities included $38.3 million and $41.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans as discussed in Note 9. At September 30, 2011 we maintained investments in bonds that have contractual maturity dates ranging from January 2012 through January 2016.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.3 million in an unrealized loss position of $0.2 million as of September 30, 2011. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary as of September 30, 2011. We also maintained several bonds with a cumulative fair value of $9.9 million in an unrealized loss position of less than $0.1 million as of September 30, 2011. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment-grade, we do not consider this impairment to be other-than-temporary as of September 30, 2011.

At September 30, 2010, we did not maintain any investments that were in an unrealized loss position. In fiscal 2009, we recorded a $5.4 million noncash charge to impair certain available-for sale investments during the year ended September 30, 2009 due to the conditions of the financial markets at that time.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Atmos Gathering Company (AGC) owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we were to be paid from future production generated from the assets.

As discussed in Note 13, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, we performed an impairment assessment of these assets during the third fiscal quarter and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $6 million and recorded a pre-tax noncash impairment loss of approximately $11 million. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired.

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of September 30, 2011:

	September 30, 2011
	(In thousands)
Carrying Amount	$2,212,565
Fair Value	$2,560,945

6. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

consolidated balance sheets at September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Operating revenues	$80,028	$69,855	$99,969
Purchased gas cost	48,759	42,419	72,945
Gross profit	31,269	27,436	27,024
Operating expenses	16,854	15,151	15,988
Operating income	14,415	12,285	11,036
Other nonoperating expense	(196)	(294)	(428)
Income from discontinued operations before income taxes	14,219	11,991	10,608
Income tax expense	5,502	4,425	2,929
Net income	$ 8,717	$ 7,566	$ 7,679

The following table presents balance sheet data related to assets held for sale.

	September 30, 2011
	(In thousands)
Net plant, property & equipment	$127,577
Gas stored underground	11,931
Other current assets	786
Deferred charges and other assets	277
Assets held for sale	$140,571
Accounts payable and accrued liabilities	$ 1,917
Other current liabilities	4,877
Regulatory cost of removal	10,498
Deferred credits and other liabilities	1,153
Liabilities held for sale	$ 18,445

7. Debt

Long-term debt

Long-term debt at September 30, 2011 and 2010 consisted of the following:

	2011	2010
	(In thousands)	
Unsecured 7.375% Senior Notes, redeemed May 2011	$ —	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	—
Medium term notes		
Series A, 1995-2, 6.27%, redeemed December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term notes due in installments through 2013	262	393
Total long-term debt	2,212,565	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(4,014)	(3,014)
Current maturities	(2,434)	(360,131)
	$2,206,117	$1,809,551

As noted above, our unsecured 10% notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011, using commercial paper borrowings. We replaced these senior notes on June 10, 2011 with $400 million 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks discussed in Note 4. Substantially all of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Prior to the third quarter of fiscal 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. On September 30, 2011, we renewed our 364-day revolving line of credit facility used to backstop letters of credit for our regulated operations and increased the borrowing capacity from $6.25 million to $10 million. As a result of these changes, we have $985 million of working capital funding from our commercial paper program and four committed revolving credit facilities with third-party lenders.

At September 30, 2011 and 2010, there was $206.4 million and $126.1 million outstanding under our commercial paper program. As of September 30, 2011 our commercial paper had maturities of less than one week with interest rates of 0.29 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding. The first facility is a five-year $750 million unsecured facility, expiring May 2016, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At September 30, 2011, there were no borrowings under this facility, but we had $206.4 million of commercial paper outstanding leaving $543.6 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2011, there were no borrowings outstanding under this facility.

The third facility is a $10 million revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate. At September 30, 2011, there were no borrowings outstanding under this credit facility; however, letters of credit totaling $5.9 million had been issued under the facility at September 30, 2011, which reduced the amount available by a corresponding amount.

The availability of funds under these 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 each of these 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, 2011, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $181.3 million outstanding under this facility at September 30, 2011.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2011, there were no borrowings outstanding under this credit facility. However, at September 30, 2011, AEM letters of credit totaling $20.2 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 $129.8 million at September 30, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.33 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2011, AEM's net working capital was $131.8 million and its tangible net worth was $144.5 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at September 30, 2011.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities prior to our $400 million senior notes offering in June 2011. At September 30, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, 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.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of September 30, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2011 were as follows (in thousands):

2012	$ 2,434
2013	250,131
2014	—
2015	500,000
2016	—
Thereafter	1,460,000
	$2,212,565

8. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 our Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Stock-Based Compensation Plans

Total stock-based compensation expense was $11.6 million, $12.7 million and $14.5 million for the fiscal years ended September 30, 2011, 2010 and 2009, 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, time-lapse restricted stock units, 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.

As of September 30, 2011, 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. In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange. As of September 30, 2011, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 319,700 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

Employees who are granted shares of time-lapse restricted stock under our LTIP have a nonforfeitable right to dividends that are paid at the same rate at which they are paid on shares of stock without restrictions. In addition, employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Both time-lapse restricted stock and time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in either the time-lapse restricted stock or time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividends that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividends on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2011, 2010 and 2009:

	2011		2010		2009	
	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	1,293,960	$27.28	1,295,841	$27.23	1,096,770	$29.04
Granted	491,345	33.10	551,278	29.07	711,909	25.76
Vested	(464,321)	27.21	(493,957)	29.24	(499,267)	29.05
Forfeited	(56,842)	27.56	(59,202)	26.54	(13,571)	28.92
Nonvested at end of year	1,264,142	$29.56	1,293,960	$27.28	1,295,841	$27.23

As of September 30, 2011, there was $18.0 million of total unrecognized compensation cost related to nonvested time-lapse restricted shares and restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2011, 2010 and 2009 was $12.6 million, $14.4 million and $14.5 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2011		2010		2009	
	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	434,962	$22.46	611,227	$21.88	913,841	$22.54
Granted	—	—	—	—	—	—
Exercised	(348,196)	22.54	(176,265)	20.44	(130,965)	21.99
Forfeited	—	—	—	—	—	—
Expired	—	—	—	—	(171,649)	25.31
Outstanding at end of year[1]	86,766	$22.16	434,962	$22.46	611,227	$21.88
Exercisable at end of year[2]	86,766	$22.16	434,962	$22.46	611,227	$21.88

(1) The weighted-average remaining contractual life for outstanding options was 1.7 years, 1.6 years, and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of outstanding options was $0.3 million, $1.6 million and $2.1 million for fiscal years 2011, 2010 and 2009.

(2) The weighted-average remaining contractual life for exercisable options was 1.7 years, 1.6 years and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of exercisable options was $0.3 million, $1.6 million and $2.1 million for the fiscal years 2011, 2010 and 2009.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2011, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price
$21.23 to $22.99	71,064	1.4	$21.31
$23.00 to $26.19	15,702	3.3	$26.00
$21.23 to $26.19	86,766	1.7	$22.16

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$7,848	$3,604	$2,880
Income tax benefit from stock option exercises	$1,010	$ 547	$ 177
Total intrinsic value of options exercised	$1,263	$ 239	$ 262

As of September 30, 2011, there was no unrecognized compensation cost related to nonvested stock options.

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

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

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

Other Discretionary Compensation Plans

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

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure 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.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2011				
Unrecognized transition obligation	$ —	$ —	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	—	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$182,113	$30,654	$ 41,899	$254,666
September 30, 2010				
Unrecognized transition obligation	$ —	$ —	$ 4,731	$ 4,731
Unrecognized prior service cost	(842)	—	(10,311)	(11,153)
Unrecognized actuarial loss	159,539	30,753	25,694	215,986
	$158,697	$30,753	$ 20,114	$209,564

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2011, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to 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 credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applied 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 are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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

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

During fiscal 2011 and 2009, we contributed $0.9 million and $21.0 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2010, we did not make any contributions to our pension plans. Based upon market conditions subsequent to September 30, 2011, the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds.

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

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

The following table presents asset allocation information for the Master Trust as of September 30, 2011 and 2010.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2011	Actual Allocation September 30 2010
Domestic equities	35%-55%	40.4%	44.1%
International equities	10% - 20%	13.6%	14.4%
Fixed income	10%-30%	21.3%	19.0%
Company stock	5%-15%	13.5%	11.3%
Other assets	5%-15%	11.2%	11.2%

At September 30, 2011 and 2010, the Plan held 1,169,700 shares of our common stock, which represented 13.5 percent and 11.3 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.6 million during fiscal 2011 and 2010.

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 September 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 September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%(1)	5.52%	7.57%
Rate of compensation increase	3.50%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	7.75%	8.25%	8.25%	8.25%	8.25%

(1) The discount rate for the Pension Account Plan increased from 5.39% to 5.68% effective January 1, 2011 due to a curtailment gain recorded in the current fiscal year.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 414,489	$ 391,915
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 407,536	$ 380,045
Service cost	14,384	13,499
Interest cost	22,264	20,870
Actuarial loss	12,944	19,809
Benefits paid	(27,534)	(26,687)
Curtailments	(162)	—
Benefit obligation at end of year	429,432	407,536
Change in plan assets:		
Fair value of plan assets at beginning of year	301,708	301,146
Actual return on plan assets	5,154	27,249
Employer contributions	876	—
Benefits paid	(27,534)	(26,687)
Fair value of plan assets at end of year	280,204	301,708
Reconciliation:		
Funded status	(149,228)	(105,828)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(149,228)	$(105,828)

Net periodic pension cost for the Plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 14,384	$ 13,499	$ 12,951
Interest cost	22,264	20,870	24,060
Expected return on assets	(24,817)	(25,280)	(24,950)
Amortization of prior service cost	(429)	(960)	(946)
Recognized actuarial loss	9,498	9,290	3,742
Curtailment gain	(40)	—	—
Net periodic pension cost	$ 20,860	$ 17,419	$ 14,857

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2011 and 2010. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2.

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In addition to the assets shown below, the Master Trust had net accounts receivable of $0.4 million and $0.1 million at September 30, 2011 and 2010 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$ 94,336	$ —	$ —	$ 94,336
Money market funds	—	9,383	—	9,383
Registered investment companies	27,236	—	—	27,236
Common/collective trusts	53,309	—	—	53,309
Government securities	4,946	18,907	—	23,853
Corporate bonds	—	33,636	—	33,636
Limited partnerships	—	37,806	—	37,806
Real estate	—	—	200	200
Total investments at fair value	$179,827	$99,732	$200	$279,759

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$116,315	$ —	$ —	$116,315
Money market funds	—	10,013	—	10,013
Registered investment companies	32,601	—	—	32,601
Common/collective trusts	—	48,920	—	48,920
Government securities	5,548	16,296	—	21,844
Corporate bonds	—	33,987	—	33,987
Limited partnerships	—	37,691	—	37,691
Real estate	—	—	200	200
Total investments at fair value	$154,464	$146,907	$200	$301,571

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. There were no changes in the fair value of the Level 3 assets during the year ended September 30, 2011.

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 (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 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 September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Rate of compensation increase	3.50%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 104,363	$ 99,673
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 108,919	$ 102,747
Service cost	2,768	2,476
Interest cost	5,825	5,224
Actuarial loss	2,140	3,043
Benefits paid	(7,537)	(4,571)
Benefit obligation at end of year	112,115	108,919
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	7,537	4,571
Benefits paid	(7,537)	(4,571)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(112,115)	(108,919)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(112,115)	$(108,919)

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Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2011 and 2010, assets held in the rabbi trusts consisted of available-for-sale securities of $38.3 million and $41.5 million, which are included in our fair value disclosures in Note 5.

Net periodic pension cost for the supplemental plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 2,768	$2,476	$ 1,985
Interest cost	5,825	5,224	6,056
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	187	212
Recognized actuarial loss	2,239	1,999	324
Curtailment	—	—	1,645
Net periodic pension cost	$10,832	$9,886	$10,222

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 2011 and 2010 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2011	2010
	(In thousands)	
Projected Benefit Obligation	$112,115	$108,919
Accumulated Benefit Obligation	104,363	99,673
Fair Value of Plan Assets	—	—

Estimated Future Benefit Payments

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

	Pension Plans	Supplemental Plans
	(In thousands)	
2012	$ 35,286	$25,116
2013	33,109	6,910
2014	31,753	4,738
2015	30,633	6,862
2016	30,648	4,622
2017-2021	146,923	43,625

Postretirement Benefits

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

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Atmos Retiree Medical Plan. Starting on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Atmos Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional 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 $31.5 million to our postretirement benefits plan during fiscal 2012.

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 diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2011 and 2010.

	Actual Allocation September 30	
Security Class	**2011**	**2010**
Diversified investment funds	96.8%	97.5%
Cash and cash equivalents	3.2%	2.5%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 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 September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2010, 2009 and 2008. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Expected return on plan assets	5.00%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	8.00%	8.00%	7.50%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2018	2016	2016	2015	2015

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 228,234	$ 209,732
Service cost	14,403	13,439
Interest cost	12,813	12,071
Plan participants' contributions	2,892	2,734
Actuarial loss	17,966	2,980
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Benefit obligation at end of year	263,694	228,234
Change in plan assets:		
Fair value of plan assets at beginning of year	53,033	47,646
Actual return on plan assets	(1,500)	3,551
Employer contributions	11,254	11,824
Plan participants' contributions	2,892	2,734
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Fair value of plan assets at end of year	53,065	53,033
Reconciliation:		
Funded status	(210,629)	(175,201)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(210,629)	$(175,201)

Net periodic postretirement cost for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$14,403	$13,439	$11,786
Interest cost	12,813	12,071	14,080
Expected return on assets	(2,727)	(2,460)	(2,292)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	—
Recognized actuarial loss	347	374	—
Net periodic postretirement cost	$24,897	$23,485	$25,085

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:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 4,155	$ (3,479)
Effect on postretirement benefit obligation	$30,159	$(25,578)

We are currently recovering other postretirement benefits costs through our regulated rates under accrual accounting as prescribed by accounting principles generally accepted in the United States 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 this accounting method 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.

The following table sets forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2011 and 2010. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,707	$—	$ 1,707
Registered investment companies	51,358	—	—	51,358
Total investments at fair value	$51,358	$1,707	$—	$53,065

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,307	$—	$ 1,307
Registered investment companies	51,726	—	—	51,726
Total investments at fair value	$51,726	$1,307	$—	$53,033

Estimated Future Benefit Payments

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

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2012	$31,519	$ 3,293	$—	$ 34,812
2013	13,272	3,895	—	17,167
2014	15,271	4,491	—	19,762
2015	16,789	5,026	—	21,815
2016	18,333	5,672	—	24,005
2017-2021	99,139	38,238	—	137,377

Defined Contribution Plans

As of September 30, 2011, 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 Holdings, LLC 401K Profit-Sharing Plan (the AEH 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $10.2 million, $9.8 million, and $9.3 million for fiscal years 2011, 2010 and 2009. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for fiscal years 2011, 2010 or 2009. At September 30, 2011 and 2010, the Retirement Savings Plan held 4.5 percent and 4.3 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH 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 75 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 four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 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 AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.3 million, $1.3 million and $1.2 million for fiscal years 2011, 2010 and 2009.

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, 2011 and 2010:

	September 30	
	2011	2010
	(In thousands)	
Billed accounts receivable	$216,145	$223,129
Unbilled revenue	48,006	47,423
Other accounts receivable	16,592	15,356
Total accounts receivable	280,743	285,908
Less: allowance for doubtful accounts	(7,440)	(12,701)
Net accounts receivable	$273,303	$273,207

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other current assets

Other current assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30 2011	September 30 2010
	(In thousands)	
Assets from risk management activities	$ 18,344	$ 20,575
Deferred gas costs	33,976	22,701
Taxes receivable	9,215	19,382
Current deferred tax asset	76,725	53,926
Prepaid expenses	22,499	24,754
Current portion of leased assets receivable	2,013	2,973
Materials and supplies	4,113	3,940
Assets held for sale	140,571	—
Other	9,015	2,744
Total	$316,471	$150,995

As discussed in Note 6, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2011 and 2010:

	September 30 2011	September 30 2010
	(In thousands)	
Production plant	$ 7,412	$ 17,360
Storage plant	198,422	193,155
Transmission plant	1,126,509	1,108,398
Distribution plant	4,496,263	4,339,277
General plant	737,850	671,953
Intangible plant	41,096	54,253
	6,607,552	6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less: accumulated depreciation and amortization	(1,668,876)	(1,749,243)
Net property, plant and equipment	$ 5,147,918	$ 4,793,075

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Marketable securities	$ 52,633	$ 41,466
Regulatory assets	278,920	254,809
Deferred financing costs	35,149	35,761
Assets from risk management activities	998	937
Other	16,093	22,403
Total	$383,793	$355,376

Other current liabilities

Other current liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Customer credit balances and deposits	$106,743	$114,215
Accrued employee costs	38,558	40,642
Deferred gas costs	8,130	43,333
Accrued interest	37,557	42,901
Liabilities from risk management activities	15,453	49,673
Taxes payable	57,853	56,616
Pension and postretirement obligations	33,036	14,815
Regulatory cost of removal accrual	35,078	30,953
Liabilities held for sale	18,445	—
Other	16,710	20,492
Total	$367,563	$413,640

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Postretirement obligations	$202,709	$167,899
Retirement plan obligations	236,227	207,234
Customer advances for construction	13,967	15,466
Regulatory liabilities	13,823	6,112
Asset retirement obligation	13,574	11,432
Uncertain tax positions	—	6,731
Liabilities from risk management activities	78,089	8,924
Other	6,306	6,366
Total	$564,695	$430,164

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

11. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

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

	2011	2010	2009
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$198,884	$198,273	$183,299
Less: Income from continuing operations allocated to participating securities	2,077	2,029	1,712
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from continuing operations per share — Basic	$ 2.18	$ 2.14	$ 1.99
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$ 8,717	$ 7,566	$ 7,679
Less: Income from discontinued operations allocated to participating securities	91	77	72
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from discontinued operations per share — Basic	$ 0.10	$ 0.08	$ 0.09
Net income per share — Basic	$ 2.28	$ 2.22	$ 2.08

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Effect of dilutive stock options and other shares	4	5	4
Income from continuing operations available to common shareholders	$196,811	$196,249	$181,591
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from continuing operations per share — Diluted	$ 2.17	$ 2.12	$ 1.98
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from discontinued operations per share — Diluted	$ 0.10	$ 0.08	$ 0.09
Net income per share — Diluted	$ 2.27	$ 2.20	$ 2.07

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2011 and 2010. There were approximately 70,000 out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2009.

12. Income Taxes

The components of income tax expense from continuing operations for 2011, 2010 and 2009 were as follows:

	2011	2010	2009
		(In thousands)	
Current			
Federal	$(11,204)	$(72,234)	$(37,141)
State	6,533	6,179	8,720
Deferred			
Federal	112,612	179,271	134,912
State	5,920	11,429	(8,739)
Investment tax credits	(172)	(283)	(390)
	$113,689	$124,362	$ 97,362

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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 2011, 2010 and 2009 are set forth below:

	2011	2010	2009
		(In thousands)	
Tax at statutory rate of 35%	$109,401	$112,922	$98,231
Common stock dividends deductible for tax reporting	(1,930)	(1,785)	(1,591)
Penalties	2,294	107	72
Settlement of uncertain tax positions	(4,950)	—	—
State taxes (net of federal benefit)	8,184	11,445	(13)
Other, net	690	1,673	663
Income tax expense	$113,689	$124,362	$97,362

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, 2011 and 2010 are presented below:

	2011	2010
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 10,327	$ 9,182
Customer advances	5,271	5,723
Nonqualified benefit plans	43,924	43,427
Postretirement benefits	62,274	57,386
Treasury lock agreements	20,060	3,211
Unamortized investment tax credit	120	183
Tax net operating loss and credit carryforwards	95,293	63,621
Difference between book and tax on mark to market accounting	8,039	2,159
Other, net	3,529	4,559
Total deferred tax assets	248,837	189,451
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,108,063)	(940,914)
Pension funding	(7,533)	(14,936)
Gas cost adjustments	(13,570)	(6,473)
Cost expensed for tax purposes and capitalized for book purposes	(3,039)	(2,330)
Total deferred tax liabilities	(1,132,205)	(964,653)
Net deferred tax liabilities	$ (883,368)	$(775,202)
Deferred credits for rate regulated entities	$ 325	$ 587

At September 30, 2011, we had $10.1 million of federal alternative minimum tax credit carryforwards, $75.2 million of federal net operating loss carryforwards and $9.9 million of state net operating loss carryforwards. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2016 and 2029.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At September 30, 2010, we had accrued liabilities associated with uncertain tax positions totaling $6.7 million. During the fiscal year ended September 30, 2011, the IRS completed its audit of fiscal years 2005-2007. All uncertain tax positions were effectively settled upon completion of the audit. As a result of the settlement, we reduced our unrecognized tax benefits by $6.7 million in the second quarter of fiscal 2011. Income tax expense was reduced by $5.0 million in the second quarter due to the realization of the tax positions which were previously uncertain. As of September 30, 2011, we had no liabilities associated with uncertain tax positions.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.01 million, $0.5 million and $0.1 million related to penalty and interest expenses during the fiscal years ended September 30, 2011, 2010 and 2009.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2007.

13. Commitments and Contingencies

Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict will be overturned on appeal.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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, Tennessee, Keokuk, Iowa and Owensboro, Kentucky, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa, Kentucky and the United States Environmental Protection Agency.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from \$3.49 to \$6.36 per Mcf. Purchases under these contracts totaled \$1,498.6 million, \$1,562.8 million and \$1,484.5 million for 2011, 2010 and 2009.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$274,985
2013	102,959
2014	82,235
2015	—
2016	—
Thereafter	—
	$460,179

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$25,362
2013	16,711
2014	9,988
2015	4,130
2016	278
Thereafter	165
	$56,634

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

Since that time, we have fully cooperated with FERC during this investigation. In August 2011, the FERC issued a Notice of Alleged Violations stating that it preliminarily determined that Atmos Energy Corporation and its subsidiaries, Atmos Energy Marketing, LLC (AEM) and Trans Louisiana Gas Pipeline, Inc. (TLGP) violated Sections 284.8(h)(2) and 1c.1 of the Commission's regulations through flipping and AEM violated the Commission's shipper-must-have-title requirement and the associated FERC gas tariffs of various pipelines.

The Company and FERC are currently involved in settlement discussions. We have accrued what we believe is an adequate amount for the anticipated resolution of this matter.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division have agreed to a program of installing 100,000 replacements during the next fiscal year, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing

35,852 lines for a cost of $49.7 million as of September 30, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

14. Leases

Leasing Operations

A subsidiary of AEH has constructed electric peaking power-generating plants and associated facilities and entered into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2011 and 2010, we had receivables of $2.0 million and $7.8 million and recognized income of $0.5 million, $0.9 million and $1.2 million for fiscal years 2011, 2010 and 2009. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts
	(In thousands)
2012	$2,013
Thereafter	—
Total minimum lease receipts	$2,013

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 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 and $1.3 million at September 30, 2011 and 2010. Accumulated depreciation for these capital leases totaled $0.9 and $0.8 million at September 30, 2011 and 2010. 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, 2011 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2012	$ 186	$ 17,718
2013	186	16,846
2014	186	16,519
2015	186	15,455
2016	186	14,921
Thereafter	264	118,108
Total minimum lease payments	1,194	$199,567
Less amount representing interest	406	
Present value of net minimum lease payments	$ 788	

Consolidated lease and rental expense amounted to $19.1 million, $16.0 million and $13.6 million for fiscal 2011, 2010 and 2009.

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, primarily consisting of letters of credit, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2011, 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. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2011 and 2010.

	September 30, 2011	September 30, 2010
Investment grade	54%	58%
Non-investment grade	46%	42%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2011. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment(1)	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 16	$ 16
Non-investment grade counterparties	—	1,081	1,081
	$—	$1,097	$1,097

(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 fiscal 2011, 2010 and 2009 are presented below.

	2011	2010	2009
		(In thousands)	
Cash paid for interest	$157,976	$161,925	$163,554
Cash received for income taxes	$ (8,329)	$(63,677)	$(36,405)

There were no significant noncash investing and financing transactions during fiscal 2011, 2010 and 2009. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

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 over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

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

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Summarized income statements and capital expenditures by segment are shown in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,530,980	$ 87,141	$1,729,513	$ —	$4,347,634
Intersegment revenues	883	132,232	295,380	(428,495)	—
	2,531,863	219,373	2,024,893	(428,495)	4,347,634
Purchased gas cost	1,487,499	—	1,959,893	(426,999)	3,020,393
Gross profit	1,044,364	219,373	65,000	(1,496)	1,327,241
Operating expenses					
Operation and maintenance	348,083	70,401	32,308	(1,502)	449,290
Depreciation and amortization	196,909	25,997	4,193	—	227,099
Taxes, other than income	161,371	14,700	2,612	—	178,683
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	706,363	111,098	69,383	(1,502)	885,342
Operating income (loss)	338,001	108,275	(4,383)	6	441,899
Miscellaneous income	16,557	4,715	657	(430)	21,499
Interest charges	115,802	31,432	4,015	(424)	150,825
Income (loss) from continuing operations before income taxes	238,756	81,558	(7,741)	—	312,573
Income tax expense (benefit)	84,755	29,143	(209)	—	113,689
Income (loss) from continuing operations	154,001	52,415	(7,532)	—	198,884
Income from discontinued operations, net of tax	8,717	—	—	—	8,717
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ —	$ 207,601
Capital expenditures	$ 496,899	$118,452	$ 7,614	$ —	$ 622,965

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,841,768	$ 97,023	$1,781,044	$ —	$4,719,835
Intersegment revenues	870	105,990	365,614	(472,474)	—
	2,842,638	203,013	2,146,658	(472,474)	4,719,835
Purchased gas cost	1,820,627	—	2,032,567	(470,864)	3,382,330
Gross profit	1,022,011	203,013	114,091	(1,610)	1,337,505
Operating expenses					
Operation and maintenance	355,357	72,249	34,517	(1,610)	460,513
Depreciation and amortization	185,147	21,368	5,074	—	211,589
Taxes, other than income	171,338	12,358	4,556	—	188,252
Total operating expenses	711,842	105,975	44,147	(1,610)	860,354
Operating income	310,169	97,038	69,944	—	477,151
Miscellaneous income (expense)	1,567	135	3,859	(5,717)	(156)
Interest charges	118,319	31,174	10,584	(5,717)	154,360
Income from continuing operations before income taxes	193,417	65,999	63,219	—	322,635
Income tax expense	75,034	24,513	24,815	—	124,362
Income from continuing operations	118,383	41,486	38,404	—	198,273
Income from discontinued operations, net of tax	7,566	—	—	—	7,566
Net income	$ 125,949	$ 41,486	$ 38,404	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 8,986	$ —	$ 542,636

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2009				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,883,997	$119,427	$1,865,687	$ —	$4,869,111
Intersegment revenues	799	90,231	418,301	(509,331)	—
	2,884,796	209,658	2,283,988	(509,331)	4,869,111
Purchased gas cost	1,887,192	—	2,169,880	(507,639)	3,549,433
Gross profit	997,604	209,658	114,108	(1,692)	1,319,678
Operating expenses					
Operation and maintenance	361,123	85,249	41,368	(2,036)	485,704
Depreciation and amortization	187,050	20,413	4,521	—	211,984
Taxes, other than income	166,854	10,231	3,157	—	180,242
Asset impairments	4,599	602	181	—	5,382
Total operating expenses	719,626	116,495	49,227	(2,036)	883,312
Operating income	277,978	93,163	64,881	344	436,366
Miscellaneous income (expense)	6,002	1,433	6,399	(16,901)	(3,067)
Interest charges	123,863	30,982	14,350	(16,557)	152,638
Income from continuing operations before income taxes	160,117	63,614	56,930	—	280,661
Income tax expense	50,989	22,558	23,815	—	97,362
Income from continuing operations	109,128	41,056	33,115	—	183,299
Income from discontinued operations, net of tax	7,679	—	—	—	7,679
Net income	$ 116,807	$ 41,056	$ 33,115	$ —	$ 190,978
Capital expenditures	$ 379,500	$108,332	$ 21,662	$ —	$ 509,494

The following table summarizes our revenues by products and services for the fiscal year ended September 30. Prior-year amounts have been restated to reflect the new operating segments.

	2011	2010	2009
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,570,723	$1,784,051	$1,768,082
Commercial	698,366	787,433	807,109
Industrial	106,569	110,280	132,487
Public authority and other	69,176	70,402	88,972
Total gas sales revenues	2,444,834	2,752,166	2,796,650
Transportation revenues	59,547	58,511	56,162
Other gas revenues	26,599	31,091	31,185
Total natural gas distribution revenues	2,530,980	2,841,768	2,883,997
Regulated transmission and storage revenues	87,141	97,023	119,427
Nonregulated revenues	1,729,513	1,781,044	1,865,687
Total operating revenues	$4,347,634	$4,719,835	$4,869,111

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at September 30, 2011 and 2010 by segment is presented in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

18. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2011:				
Operating revenues				
Natural gas distribution	$ 703,462(1)	$1,077,414(2)	$ 407,031	$ 343,956
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,133,262	1,581,497	843,615	789,260
Gross profit	364,724(1)	453,668(2)	266,805	242,044
Operating income	155,289(1)	211,199(2)	34,078	41,333
Income (loss) from continuing operations	71,100	128,160	(1,474)	1,098
Income from discontinued operations	2,897	4,049	908	863
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2010:				
Operating revenues				
Natural gas distribution	$ 781,841(3)	$1,333,872(4)	$ 396,319	$ 330,606(5)
Regulated transmission and storage	46,860	55,181	44,957	56,015
Nonregulated	548,016	677,032	427,405	494,205
Intersegment eliminations	(104,918)	(157,935)	(107,376)	(102,245)
	1,271,799	1,908,150	761,305	778,581
Gross profit	403,003(3)	445,444(4)	247,666	241,392(5)
Operating income	186,598(3)	219,757(4)	32,259	38,537(5)
Income (loss) from continuing operations	90,975	111,283	(4,229)	244
Income from discontinued operations	2,355	2,843	1,075	1,293
Net income (loss)	93,330	114,126	(3,154)	1,537
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	0.03	$ 0.01	$ 0.02
Net income (loss) per share — basic	$ 1.00	$ 1.22	$ (0.03)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	$ 0.03	$ 0.01	$ 0.02
Net income (loss) per share — diluted	$ 1.00	$ 1.22	$ (0.03)	$ 0.02

(1) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $23.7 million, $8.8 million and $4.8 million.

(2) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $35.8 million, $11.2 million and $6.7 million.

(3) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $21.1 million, $7.8 million and $4.0 million.

(4) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $32.1 million, $8.9 million and $4.8 million.

(5) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $7.7 million, $5.2 million and $1.7 million.

ITEM 9. *Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.*

None.

ITEM 9A. *Controls and Procedures.*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2011, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ KIM R. COCKLIN	/s/ FRED E. MEISENHEIMER
Kim R. Cocklin President and Chief Executive Officer	Fred E. Meisenheimer Senior Vice President and Chief Financial Officer

November 22, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, 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, 2011, 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, 2011 and 2010, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011 of Atmos Energy Corporation and our report dated November 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

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, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2011, 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	64	14	Executive Chairman of the Board
Kim R. Cocklin	60	5	President and Chief Executive Officer
Louis P. Gregory	56	11	Senior Vice President and General Counsel
Michael E. Haefner	51	3	Senior Vice President, Human Resources
Fred E. Meisenheimer	67	11	Senior Vice President and Chief Financial Officer

Robert W. Best was named Executive Chairman of the Board on October 1, 2010. From March 1997 through September 2008, Mr. Best served the Company as Chairman of the Board, President and Chief Executive Officer. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

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

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

Fred E. Meisenheimer was named Senior Vice President and Chief Financial Officer in February 2009. Mr. Meisenheimer previously served the Company as Vice President and Controller from July 2000 through

May 2009, interim Chief Financial Officer in January 2009 and Treasurer from November 2009 through February 2011.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance."

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

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

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/ FRED E. MEISENHEIMER

Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer

Date: November 22, 2011

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin and Fred. E. Meisenheimer, 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/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 22, 2011
/s/ FRED E. MEISENHEIMER Fred E. Meisenheimer	Senior Vice President and Chief Financial Officer	November 22, 2011
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 22, 2011
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 22, 2011
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 22, 2011
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 22, 2011
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 22, 2011
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 22, 2011
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 22, 2011
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 22, 2011
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 22, 2011
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 22, 2011
/s/ RICHARD WARE II Richard Ware II	Director	November 22, 2011

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2011

	Balance at beginning of period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
2011					
Allowance for doubtful accounts	$12,701	$2,201	$—	$ 7,462[1]	$ 7,440
2010					
Allowance for doubtful accounts	$11,478	$7,694	$—	$ 6,471[1]	$12,701
2009					
Allowance for doubtful accounts	$15,301	$7,769	$—	$11,592[1]	$11,478

(1) Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition	
2.1	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit 4.1 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 5⅛% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(c)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(d)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(e)	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)
4.7(f)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(g)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Material Contracts	
10.1	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)
10.2	Revolving Credit Agreement, dated as of May 2, 2011 among Atmos Energy Corporation, the Lenders from time to time parties thereto, The Royal Bank of Scotland plc as Administrative Agent, Crédit Agricole Corporate and Investment Bank as Syndication Agent, Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A. as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated May 2, 2011 (File No. 1-10042)
10.3(a)	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and The Royal Bank of Scotland plc, as co-syndication agent and a bank; and Natixis, New York Branch, Crédit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3(b)	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010, (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.4(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	Exhibit 10.6(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.4(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	Exhibit 10.6(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.5	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(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)
10.7(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)
10.8(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)
10.8(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)
10.9(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	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)
10.9(e)*	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)
10.10(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)
10.10(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)
10.10(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)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2010	Exhibit 10.12 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(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)
10.13(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.4 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.5 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.14*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
12	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	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2011
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
101.INS	XBRL Instance Document***	
101.SCH	XBRL Taxonomy Extension Schema***	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase***	
101.DEF	XBRL Taxonomy Extension Definition Linkbase***	
101.LAB	XBRL Taxonomy Extension Labels Linkbase***	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase***	

* 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.

*** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

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

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas**	**75240**
(Address of principal executive offices)	*(Zip code)*

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.45) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

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

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

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2012, was $2,764,486,845.

As of November 6, 2012, the registrant had 90,240,464 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 13, 2013, are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
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
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
Mid-Tex Cities	Represents 440 of the 441 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SRF	Stable Rate Filing
WNA	Weather Normalization Adjustment

PART I

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

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in nine states located primarily in the South, which makes us one of the country's largest natural-gas-only distributors based on number of customers. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

In August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers and announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. After the closing of the Georgia transaction, we will operate in eight states.

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

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while safely operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have delivered excellent shareholder value by growing our earnings and increasing our dividends for over 25 consecutive years. Through fiscal 2005, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. Since that time, we have achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations.

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

Operating Segments

We operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment represents approximately 65 percent of our consolidated net income. This segment is comprised of the following six regulated divisions, presented in order of total rate base, covering service areas in nine states:

- Atmos Energy Mid-Tex Division,
- Atmos Energy Kentucky/Mid-States Division,
- Atmos Energy Louisiana Division,
- Atmos Energy West Texas Division,
- Atmos Energy Mississippi Division and
- Atmos Energy Colorado-Kansas Division

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

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia and Virginia. See Note 6 in the consolidated financial statements for a description of the completed sale of our Missouri, Illinois and Iowa service areas and the anticipated sale of our Georgia distribution operations. In addition, we transport natural gas for others through our distribution system.

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

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

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

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for approximately 97 percent of residential and commercial margins in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset the effect of lower gas usage when weather is warmer than normal and decrease customers' bills to offset the effect of higher gas usage when weather is colder than normal.

As of September 30, 2012 we had WNA for our residential and commercial meters in the following service areas for the following periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
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 consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. 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.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically 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 reasonable cost. Major suppliers during fiscal 2012 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, Sequent Energy Management, L.P., Texla Energy Management, Inc. 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 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2012 was on February 11, 2012, when sales to customers reached approximately 3.0 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 43 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 primarily by our Atmos Pipeline — Texas Division.

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 regulations or statutes. 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.

Below, we briefly describe our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2012, we held 1,006 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

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

Prior to fiscal 2008, this division operated under one system-wide rate structure. In fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers that allowed us to update rates for customers in these cities using an annual rate review mechanism (RRM) from fiscal 2008 through fiscal 2011, when the RRM was active. We filed a formal rate case for the Mid-Tex Division in fiscal 2012. After the conclusion of this rate case, we expect to negotiate a new rate review mechanism process. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first rates were implemented under the DARR in June 2012.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division currently operates in more than 230 communities across Georgia, Kentucky, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

On August 1, 2012, we completed the divestiture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers in 189 communities, with some of the Missouri communities located in our Atmos Energy Colorado-Kansas Division. On August 8, 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers in 19 communities. See Note 6 in the consolidated financial statements for further information regarding these divestitures.

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 nonregulated segment. Our rates in this division are updated annually through a rate stabilization clause filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. In fiscal 2008 and 2009, we reached an agreement with the West Texas service areas and the Amarillo and Lubbock service areas that allowed us to update rates for customers in these cities using an annual rate review mechanism (RRM) through fiscal 2011, when the RRM was active. We filed a formal rate case for the West Texas Division in fiscal 2012, which was approved on October 2, 2012. We expect to negotiate a new rate review mechanism process in fiscal 2013.

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, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver. We update our rates in this division through periodic formal rate filings and in Kansas through periodic infrastructure replacement filings made with each state's public service commission.

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

Division	Jurisdiction	Effective Date of Last Rate/GRIP Action	Rate Base (thousands)[1]	Authorized Rate of Return[1]	Authorized Return on Equity[1]
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	04/10/2012	879,752	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	09/01/2012	160,075	(2)	(2)
Kentucky/Mid-States	Georgia	02/02/2012	96,338[3]	8.61%	10.50% - 10.90%
	Kentucky	06/01/2010	208,702[4]	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2012	100,575	8.24%	10.00% - 10.80%
	LGS	07/01/2012	284,607	8.27%	10.40%
Mid-Tex Cities	Texas	09/01/2011	1,389,187[5]	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/01/2012	1,472,583[5]	8.50%	10.10%
Mid-Tex — Environs GRIP	Texas	06/26/2012	1,449,544[5]	8.60%	10.40%
Mississippi	Mississippi	01/11/2012	274,576	8.06%	9.75%
West Texas	Amarillo[6]	08/01/2011	(2)	(2)	9.60%
	Lubbock[6]	09/09/2011	60,892	8.19%	9.60%
	West Texas[6]	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[7]	WNA	Performance-Based Rate Program[8]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[9]	No	No	111,354
	Kansas	(2)	Yes	Yes	No	129,468
Kentucky/Mid-States	Georgia	50/50	No	Yes	Yes	63,707
	Kentucky	(2)	Yes	Yes	Yes	170,608
	Tennessee	52/48	Yes	Yes	Yes	134,927
	Virginia	51/49	Yes	Yes	No	23,335
Louisiana	Trans LA	52/48	No	Yes	No	75,607
	LGS	52/48	No	Yes	No	277,159
Mid-Tex Cities	Texas	50/50	Yes	Yes	No	1,252,548
Mid-Tex — Dallas	Texas	48/52	Yes	Yes	No	250,510
Mid-Tex — Environs	Texas	51/49	Yes	Yes	No	62,627
Mississippi	Mississippi	50/50	No	Yes	No	263,302
West Texas	Amarillo[6]	52/48	Yes	Yes	No	70,258
	Lubbock[6]	52/48	Yes	Yes	No	74,244
	West Texas[6]	52/48	Yes	Yes	No	156,935

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

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

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia

rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.68 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Mid-Tex Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

(6) On October 2, 2012, a rate case settlement was approved by the Texas Railroad Commission that combined the former Amarillo, Lubbock and West Texas jurisdictions into a single "West Texas" jurisdiction.

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

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

(9) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment represents approximately 30 percent of our consolidated net income and consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements 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. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. Rates are updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. Atmos Pipeline–Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

These operations include 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 with our pipeline system providing access to all of these basins.

Nonregulated Segment Overview

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States. Currently, this segment represents less than five percent of our consolidated net income.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

Ratemaking Activity

Overview

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

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Annual ratemaking mechanisms in place in four states that provide for an annual rate review and adjustment to rates for approximately 77 percent of our natural gas distribution gross margin.
- Accelerated recovery of capital for approximately 74 percent of our natural gas distribution gross margin.
- WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 97 percent of our natural gas distribution gross margin.
- The ability to recover the gas cost portion of bad debts for approximately 75 percent of our natural gas distribution gross margin.

Although substantial progress has been made in recent years by improving rate design across Atmos Energy's operating areas, we will continue to seek improvements in rate design to address cost variations that are related to pass-through energy costs beyond our control. Further, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our regulated revenues in the fiscal years ended September 30, 2012, 2011 and 2010 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $30.7 million, $72.4 million and $56.8 million, became effective in fiscal 2012, 2011 and 2010, as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2012	2011	2010
		(In thousands)	
Rate case filings	$ 4,309	$20,502	$23,663
Infrastructure programs	19,172	15,033	18,989
Annual rate filing mechanisms	7,044	35,216	13,757
Other ratemaking activity	167	1,675	392
	$30,692	$72,426	$56,801

Additionally, the following ratemaking efforts were initiated during fiscal 2012 but had not been completed as of September 30, 2012:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[1]	Georgia	$ 1,079
	PRP[1]	Kentucky	2,425
	PRP[1]	Virginia	101
	Rate Case[2]	Tennessee	11,230
	GRAM[3]	Georgia	1,079
Mississippi	Stable Rate Filing	Mississippi	4,830
Mid-Tex	Rate Case[4]	Railroad Commission of Texas (RRC)	46,537
West Texas	Rate Case[5]	RRC	9,427
			$76,708

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Georgia, Kentucky and Virginia PRPs were implemented on October 1, 2012.

(2) A settlement was approved on November 7, 2012 for an operating income increase of $7.5 million.

(3) Georgia Rate Adjustment Mechanism

(4) A hearing was conducted in September 2012. A final order is expected in December 2012.

(5) On October 2, 2012, the RRC approved a $6.6 million operating income increase.

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

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

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2012 Rate Case Filings:			
Colorado-Kansas	Kansas	$ 3,764	09/01/2012
West Texas — Environs	Texas	545	11/08/2011
Total 2012 Rate Case Filings		$ 4,309	
2011 Rate Case Filings:			
West Texas — Amarillo Environs	Texas	$ 78	07/26/2011
Atmos Pipeline — Texas	Texas	20,424	05/01/2011
Total 2011 Rate Case Filings		$20,502	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas[1]	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

Infrastructure Programs

As discussed above in "Natural Gas Distribution Segment Overview" and "Regulated Transmission and Storage Segment Overview," infrastructure programs such as GRIP allow our regulated companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2012, 2011 and 2010:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2012 Infrastructure Programs:				
Mid-Tex Unincorporated (Environs)(1)	12/2011	$145,671	$ 744	06/26/2012
Atmos Pipeline — Texas	12/2011	87,210	14,684	04/10/2012
Kentucky/Mid-States — Georgia(2)	09/2010	7,160	1,215	10/01/2011
Kentucky/Mid-States — Kentucky(2)	09/2012	17,347	2,529	10/01/2011
Total 2012 Infrastructure Programs		$257,388	$19,172	
2011 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2010	$ 72,980	$12,605	07/26/2011
Mid-Tex/Environs	12/2010	107,840	576	06/27/2011
West Texas/Lubbock & WT Cities Environs	12/2010	17,677	343	06/01/2011
Kentucky/Mid-States — Kentucky (2)	09/2011	3,329	468	06/01/2011
Kentucky/Mid-States — Missouri(3)	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States — Georgia(2)	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	
2010 Infrastructure Programs:				
Mid-Tex(4)	12/2009	$ 16,957	$ 2,983	09/01/2010
West Texas	12/2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	12/2009	95,504	13,405	04/20/2010
Kentucky/Mid-States — Missouri(3)	06/2009	3,578	563	03/02/2010
Colorado-Kansas — Kansas(5)	08/2009	6,917	766	12/12/2009
Kentucky/Mid-States — Georgia(2)	09/2008	6,327	909	10/01/2009
Total 2010 Infrastructure Programs		$148,441	$18,989	

(1) Incremental net utility plant investment represents the system-wide incremental investment for the Mid-Tex Division. The increase in annual operating income is for the unincorporated areas of the Mid-Tex Division only.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure.

(3) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(4) Increase relates to the City of Dallas and Environs areas of the Mid-Tex Division.

(5) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As discussed above in "Natural Gas Distribution Segment Overview," we currently have annual rate filing mechanisms in our Louisiana, Mississippi and Georgia divisions and in a portion of our Texas divisions. These mechanisms are referred to as Dallas annual rate review (DARR) in our Mid-Tex Division, stable rate filings in the Mississippi Division, the rate stabilization clause in the Louisiana Division, the Georgia Rate Adjustment Mechanism (GRAM) in the Georgia Division and previously as rate review mechanisms (RRM) in our Texas divisions. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2012 Filings:				
Louisiana	LGS	12/31/2011	$ 2,324	07/01/2012
Mid-Tex	Dallas	09/30/2011	1,204	06/01/2012
Louisiana	Trans La	09/30/2011	11	04/01/2012
Kentucky/Mid-States	Georgia	09/30/2011	(818)	02/01/2012
Mississippi	Mississippi	06/30/2011	4,323	01/11/2012
Total 2012 Filings			$ 7,044	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2010	$ 5,126	09/27/2011
Mid-Tex	Dallas	12/31/2010	1,084	09/27/2011
West Texas	Lubbock	12/31/2010	319	09/08/2011
West Texas	Amarillo	12/31/2010	(492)	08/01/2011
Louisiana	LGS	12/31/2010	4,109	07/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Settled Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	

Beginning in fiscal year 2008, we entered into RRM mechanisms within our Mid-Tex and West Texas divisions. Throughout the period of fiscal 2008 through fiscal 2011, when the RRM mechanisms were active, we were able to successfully implement new base rates within the various cities of both divisions. In fiscal 2012, we filed a rate case in both the Mid-Tex Division (for all cities except Dallas) and the West Texas Division. Following the conclusion of the Mid-Tex Division case, we expect to negotiate a new rate review mechanism process with each of the cities within both the Mid-Tex and West Texas divisions.

We continue to operate under an annual rate mechanism, DARR, with the City of Dallas, which was approved in June 2011. The first rates were implemented under the DARR in June 2012.

During fiscal 2011, the RRC's Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expense associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2012, 2011 and 2010:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2012 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 167	01/14/2012
Total 2012 Other Rate Activity			$ 167	
2011 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 641	07/01/2011
Colorado-Kansas	Kansas	Ad Valorem[1]	685	01/01/2011
Colorado-Kansas	Colorado	AMI[2]	349	12/01/2010
Total 2011 Other Rate Activity			$1,675	
2010 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 392	01/05/2010
Total 2010 Other Rate Activity			$ 392	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

(2) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of our Colorado service area.

Other Regulation

Each of our natural gas distribution divisions as well as our regulated transmission and storage division 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 transmission and distribution facilities. In addition, our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites.

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. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity, as well as authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

Competition

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

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2012, we had 4,759 employees, consisting of 4,646 employees in our regulated operations and 113 employees in our nonregulated operations.

Available Information

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

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

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2012, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors.*

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

Disruptions in the credit markets could limit our ability to access capital and increase our costs of capital.

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

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. If adverse credit conditions were to cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. Such a downgrade could further limit our access to public and/or private credit markets and increase the costs of borrowing under each source of credit.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our nonregulated segment because the commodity financial instrument markets could become unavailable to us. Our nonregulated segment depends primarily upon a committed credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. A significant reduction in the availability of this facility could require us to provide extra liquidity to support its operations or reduce some of the activities of our nonregulated segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

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

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

The slowdown in the U.S. economy in the last few years, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in improving current economic conditions, including the lowering of current high unemployment rates across the U.S. As a result, our customers may seek to use even less gas and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of health care benefits for our employees. Further, the costs to the Company of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates.

We provide a cash-balance pension plan and postretirement healthcare benefits to eligible full-time employees. The costs of providing such benefits and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement healthcare plans. Any significant declines in the value of these investments could increase the costs of our pension and postretirement healthcare plans and related funding requirements in the future. Further, our costs of providing such benefits and related funding requirements are also subject to a number of factors, including (i) 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 (ii) various actuarial calculations and assumptions, which may differ materially from actual results due primarily to changing market and economic conditions and higher or lower withdrawal rates.

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years due primarily to the Health Care Reform Act of 2010. Although the full effects of the Act should not impact the Company until 2014, the future costs of compliance with its provisions are difficult to measure at this time. Also, the costs to the Company of providing such benefits and related funding requirements could also increase materially in the future, depending on the timing of the recovery, if any, of such costs through our rates.

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

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics 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, particularly in our nonregulated business segment, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segment 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. 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. 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. 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 before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match 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. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

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

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

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

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

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 73,000 miles of pipeline and distribution lines. The pipeline replacement programs currently underway in several of our divisions typify the preventive maintenance and continual renewal that we perform on our natural gas distribution system in the nine states in which we currently operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the unfortunate pipeline incident in California in 2010, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Although we believe these costs should be ultimately recoverable through our rates, costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

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

FERC has regulatory authority over some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

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.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

Over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

We have weather-normalized rates for over 95 percent of our residential and commercial meters, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather–normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our nonregulated 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. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

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

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

Rapid increases in the costs of purchased gas would 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 enable us to serve any 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. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures to comply with the recent rule issued by the RRC's Division of Public Safety that requires natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

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

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

Cyber-attacks or acts of cyber-terrorism could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information.

Our business operations and information technology systems may be vulnerable to an attack by individuals or organizations intending to disrupt our business operations and information technology systems. We use such systems to manage our natural gas distribution and intrastate pipeline operations and other business processes. Disruption of those systems could adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline systems or serve our customers timely. Accordingly, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected. In addition, we use our information technology systems to protect confidential or sensitive customer, employee and Company information developed and maintained in the normal course of our business. Any attack on such systems that would result in the unauthorized release of customer, employee or other confidential or sensitive data could have a material adverse effect on our business reputation, increase our costs and expose us to additional material legal claims and liability. As a result, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected.

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

Our natural gas distribution and pipeline and storage businesses involve 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 maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our operations or financial results could be adversely affected.

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

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

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2012, our natural gas distribution segment owned an aggregate of 68,072 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 5,698 miles of gas transmission and gathering lines and our non-regulated segment owned 105 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 at September 30, 2012:

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	105,100
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	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	228,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated 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	60,458,299	30,549,198	91,007,497	1,590,100

(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 at September 30, 2012:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	4,248,409	108,089
	Kentucky/Mid-States Division	16,424,150	440,277
	Louisiana Division	2,636,539	161,393
	Mid-Tex Division	500,000	50,000
	Mississippi Division	3,875,429	165,402
	West Texas Division	3,375,000	106,000
Total		31,059,527	1,031,161
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		40,760,396	1,349,605

(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.

Offices

Our administrative offices and corporate headquarters are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our service territory, the majority of which are located in leased facilities. The headquarters for our nonregulated operations are 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.

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 2012 and 2011 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:

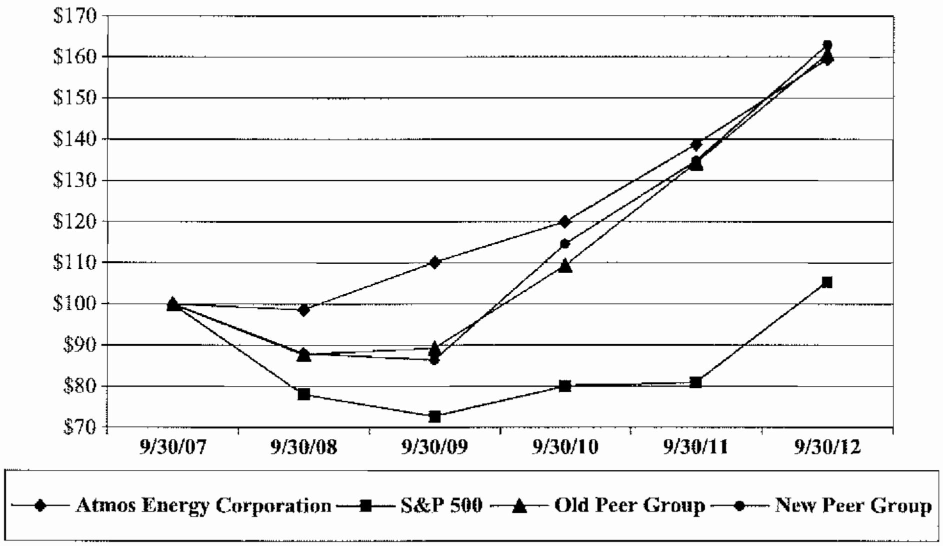
	Fiscal 2012			Fiscal 2011		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$35.40	$30.97	$.345	$31.72	$29.10	$.340
March 31	33.15	30.60	.345	34.98	31.51	.340
June 30	35.07	30.91	.345	34.94	31.34	.340
September 30	36.94	34.94	.345	34.32	28.87	.340
			$1.38			$1.36

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2012 was 17,883. 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 2012 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor's 500 Stock Index and the cumulative total return of two different customized peer company groups, the New Comparison Company Index and the Old Comparison Company Index. The New Comparison Company Index includes Questar and excludes EQT Corporation because the Board of Directors determined that Questar better fits the profile of the companies in the peer group, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2007 in our common stock, the S&P 500 Index and in the common stock of the companies in the New and Old Comparison Company Indexes, as well as a reinvestment of dividends paid on such investments throughout the period.

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



	Cumulative Total Return					
	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11	9/30/12
Atmos Energy Corporation	100.00	98.61	110.13	119.94	138.80	159.56
S&P 500	100.00	78.02	72.63	80.01	80.93	105.37
Old Peer Group	100.00	87.71	89.32	109.42	134.24	160.67
New Peer Group	100.00	88.10	86.44	114.56	134.80	162.92

The New Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by our independent compensation 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, Integrys Energy Group, Inc., National Fuel Gas, NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Questar Corporation, Vectren Corporation and WGL Holdings, Inc. The Old Comparison Company Index includes the companies listed above in the New Company Index with the exception of Questar Corporation, which replaced EQT Corporation in the Company's peer group in the current year for the reasons discussed above.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2012.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	10,094	$24.95	1,949,088
Total equity compensation plans approved by security holders	10,094	24.95	1,949,088
Equity compensation plans not approved by security holders	—	—	—
Total	10,094	$24.95	1,949,088

On September 28, 2011, the Board of Directors approved a program authorizing the repurchase of up to five million shares of common stock over a five-year period. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. We did not repurchase any shares during the fourth quarter of fiscal 2012. At September 30, 2012, there were 4,612,009 shares of repurchase authority remaining under the program.

ITEM 6. *Selected Financial Data.*

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

	Fiscal Year Ended September 30				
	2012[1]	2011[1]	2010	2009[1]	2008
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$3,438,483	$4,286,435	$4,661,060	$4,793,248	$7,039,342
Gross profit	$1,323,739	$1,300,820	$1,314,136	$1,297,682	$1,275,077
Income from continuing operations	$ 192,196	$ 189,588	$ 189,851	$ 175,026	$ 166,696
Net income	$ 216,717	$ 207,601	$ 205,839	$ 190,978	$ 180,331
Diluted income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03	$ 1.90	$ 1.84
Diluted net income per share	$ 2.37	$ 2.27	$ 2.20	$ 2.07	$ 1.99
Cash dividends declared per share	$ 1.38	$ 1.36	$ 1.34	$ 1.32	$ 1.30
Financial Condition					
Net property, plant and equipment[2]	$5,475,604	$5,147,918	$4,793,075	$4,439,103	$4,136,859
Total assets	$7,495,675	$7,282,871	$6,763,791	$6,367,083	$6,386,699
Capitalization:					
Shareholders' equity	$2,359,243	$2,255,421	$2,178,348	$2,176,761	$2,052,492
Long-term debt (excluding current maturities)	1,956,305	2,206,117	1,809,551	2,169,400	2,119,792
Total capitalization	$4,315,548	$4,461,538	$3,987,899	$4,346,161	$4,172,284

(1) Financial results for fiscal years 2012, 2011 and 2009 include a $5.3 million, $30.3 million and a $5.4 million pre-tax loss for the impairment of certain assets.

(2) Amounts shown for fiscal 2012 and 2011 are net of assets held for sale.

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

INTRODUCTION

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

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

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

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, 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

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 base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from estimates.

Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. The accounting policies discussed below are both important to the presentation of our financial condition and results of operations and require management to make difficult, subjective or complex accounting estimates. Accordingly, these critical accounting policies are reviewed periodically by the Audit Committee of the Board of Directors.

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. We meet the criteria established within accounting principles generally accepted in the United States of a cost-based, rate-regulated entity, which requires us to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements in accordance with applicable authoritative accounting standards. We apply the provisions of this standard to our regulated operations and record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities 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 it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities 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 regulated operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

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

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

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses. These objectives are more fully described in Note 4 to the consolidated financial statements.

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. Market value changes result in a change in the fair value of these financial instruments. The recognition of the changes in fair value of these financial instruments are recorded in the income statement is contingent upon whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment.

We have elected to treat forward gas supply contracts used in our regulated operations to deliver gas as normal purchases and normal sales. Financial instruments used to manage commodity price risk in our natural gas distribution segment do not impact this segment's results of operations as the realized gains and losses are ultimately recovered from ratepayers through our rates.

Our nonregulated segment also utilizes financial instruments to manage commodity price risk. We have designated the natural gas inventory held by this operating segment as the hedged item in a fair-value hedge. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges. Changes in the fair value of the inventory and designated hedges are recognized in purchased gas cost in the period of change.

Additionally, we have elected to treat fixed-price forward contracts used in our nonregulated segment to deliver gas as normal purchases and normal sales. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on open financial instruments are recorded as a component of accumulated other comprehensive income (loss) and are recognized as a component of revenue when the hedged volumes are sold.

Our nonregulated segment also uses storage swaps and futures that have not been designated as hedges. Accordingly, changes in the fair value of the inventory and designated hedges are recognized in revenue in the period of change.

Finally, financial instruments used to mitigate interest rate risk are designated as cash flow hedges. Accordingly, unrealized gains and losses are recorded as a component of accumulated other comprehensive income (loss) and are recognized as a component of interest expense over the life of the related financing arrangement.

The criteria used to determine if a financial instrument meets the definition of a derivative and qualifies for hedge accounting treatment are complex and require management to exercise professional judgment. Further, as more fully discussed below, significant changes in the fair value of these financial instruments could materially impact our financial position, results of operations or cash flows.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

The fair value of our financial instruments is subject to potentially significant volatility based numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and settlement of these financial instruments, and our creditworthiness as well as the creditworthiness of our counterparties. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

Impairment assessments — We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstance indicate that such carrying values may not be recoverable, and at least annually for goodwill, as required by US accounting standards.

The evaluation of our goodwill balances and other long-lived assets or identifiable assets for which uncertainty exists regarding the recoverability of the carrying value of such assets involves the assessment of future cash flows and external market conditions and other subjective factors that could impact the estimation of future cash flows including, but not limited to the commodity prices, the amount and timing of future cash flows, future growth rates and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affects these estimates, which could result in an impairment charge.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date 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. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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 and expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $2.3 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 million.

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and reasonably estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 13 to our consolidated financial statements.

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 56 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

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

During fiscal 2012, we earned $216.7 million, or $2.37 per diluted share, which represents a four percent increase in net income and diluted net income per share over fiscal 2011. During fiscal 2012, recent improvements in rate designs in our natural gas distribution and regulated transmission and storage segments offset an eight percent year-over-year decline in consolidated natural gas distribution throughput due to warmer weather and a 21 percent decrease in nonregulated delivered gas sales due to a nine percent decrease in consolidated sales volumes as a result of warmer weather and a decrease in per-unit margins. Additionally, results for fiscal 2012 were influenced by several non-recurring items, which increased diluted earnings per share by $0.11.

On August 1, 2012, we completed the sale of substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $128 million, pursuant to an asset purchase agreement executed on May 12, 2011. In connection with the sale, we recognized a net of tax gain of approximately $6.3 million.

On August 8, 2012, we entered into an asset purchase agreement to sell all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. Due to the pending sales transaction, the results of operations for our Georgia service area are shown in discontinued operations.

Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On July 27, 2012 we issued a notice of early redemption of these notes on August 28, 2012. We initially funded the redemption through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The facility bears interest at a one-month LIBOR based rate plus currently a margin of 0.875% which is based on the Company's credit rating. The short-term facility is expected to be repaid with the proceeds received from the issuance of new $350 million senior unsecured notes anticipated to occur in January 2013. In connection with the redemption, we paid a make-whole premium in accordance with the terms of the indenture and the Senior Notes and accrued interest at the time of redemption. In accordance with regulatory requirements, the premium will be deferred and will be recognized over the life of the new unsecured notes expected to be issued in January 2013.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2012, 2011 and 2010.

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Operating revenues	$3,438,483	$4,286,435	$4,661,060
Gross profit	1,323,739	1,300,820	1,314,136
Operating expenses	877,499	874,834	850,303
Operating income	446,240	425,986	463,833
Miscellaneous income (expense)	(14,644)	21,184	(591)
Interest charges	141,174	150,763	154,188
Income from continuing operations before income taxes	290,422	296,407	309,054
Income tax expense	98,226	106,819	119,203
Income from continuing operations	192,196	189,588	189,851
Income from discontinued operations, net of tax	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax	6,349	—	—
Net income	$ 216,717	$ 207,601	$ 205,839
Diluted net income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03
Diluted net income per share from discontinued operations	$ 0.27	$ 0.20	$ 0.17
Diluted net income per share	$ 2.37	$ 2.27	$ 2.20

Regulated operations contributed 98 percent, 104 percent and 81 percent to our consolidated net income for fiscal years 2012, 2011 and 2010. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands)		
Natural gas distribution segment	$148,369	$162,718	$125,949
Regulated transmission and storage segment	63,059	52,415	41,486
Nonregulated segment	5,289	(7,532)	38,404
Net income	$216,717	$207,601	$205,839

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

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Regulated operations	$211,428	$215,133	$167,435
Nonregulated operations	5,289	(7,532)	38,404
Consolidated net income	$216,717	$207,601	$205,839
Diluted EPS from regulated operations	$ 2.31	$ 2.35	$ 1.79
Diluted EPS from nonregulated operations	0.06	(0.08)	0.41
Consolidated diluted EPS	$ 2.37	$ 2.27	$ 2.20

We reported net income of $216.7 million, or $2.37 per diluted share for the year ended September 30, 2012, compared with net income of $207.6 million or $2.27 per diluted share in the prior year. Income from continuing operations was $192.2 million, or $2.10 per diluted share compared with $189.6 million, or $2.07 per diluted share in the prior-year period. Income from discontinued operations was $24.5 million or $0.27 per diluted share for the year, which includes the gain on sale of substantially all our assets in Missouri, Illinois and

Iowa of $6.3 million, compared with $18.0 million or $0.20 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year reduced net income by $5.0 million or $0.05 per diluted share compared with net losses recorded in the prior year of $6.6 million, or $0.07 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2011, net income included the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the pre-tax items, which are discussed in further detail below. In fiscal 2012, net income includes the net positive impact of several one-time items totaling $10.3 million, or $0.11 per diluted share related to the following amounts:

- $13.6 million positive impact of a deferred tax rate adjustment.
- $10.0 million ($6.3 million, net of tax) unfavorable impact related to a one-time donation to a donor advised fund.
- $9.9 million ($6.3 million, net of tax) favorable impact related to the cash gain recorded in association with the August 1, 2012 completion of the sale of our Iowa, Illinois and Missouri assets.
- $5.3 million ($3.3 million, net of tax) unfavorable impact related to the noncash impairment of certain assets in our nonregulated business.

We reported net income of $207.6 million, or $2.27 per diluted share for the year ended September 30, 2011, compared with net income of $205.8 million or $2.20 per diluted share in the prior year. Income from continuing operations was $189.6 million, or $2.07 per diluted share compared with $189.9 million, or $2.03 per diluted share in the prior-year period. Income from discontinued operations was $18.0 million or $0.20 per diluted share for the year, compared with $16.0 million or $0.17 per diluted share in the prior year. Unrealized losses in our nonregulated operations during fiscal 2011 reduced net income by $6.6 million or $0.07 per diluted share compared with net losses recorded in fiscal 2010 of $4.3 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2010, net income included the net positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. In fiscal 2011, net income includes the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the noncash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

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

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, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as 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.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 75 percent of our residential and commercial margins.

As discussed above, on August 1, 2012, we completed the sale of substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. On August 8, 2012 we entered into a definitive agreement to sell our natural gas distribution operations in Georgia. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Gross profit	$1,022,743	$1,017,943	$998,642	$ 4,800	$ 19,301
Operating expenses	718,282	695,855	701,791	22,427	(5,936)
Operating income	304,461	322,088	296,851	(17,627)	25,237
Miscellaneous income (expense)	(12,657)	16,242	1,132	(28,899)	15,110
Interest charges	110,642	115,740	118,147	(5,098)	(2,407)
Income from continuing operations before income taxes	181,162	222,590	179,836	(41,428)	42,754
Income tax expense	57,314	77,885	69,875	(20,571)	8,010
Income from continuing operations	123,848	144,705	109,961	(20,857)	34,744
Income from discontinued operations, net of tax	18,172	18,013	15,988	159	2,025
Gain on sale of discontinued operations, net of tax	6,349	—	—	6,349	—
Net Income	$ 148,369	$ 162,718	$125,949	$(14,349)	$ 36,769
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	244,466	275,540	307,474	(31,074)	(31,934)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	128,222	125,812	122,633	2,410	3,179
Consolidated natural gas distribution throughput from continuing operations — MMcf	372,688	401,352	430,107	(28,664)	(28,755)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	18,295	22,668	24,068	(4,373)	(1,400)
Total consolidated natural gas distribution throughput — MMcf	390,983	424,020	454,175	(33,037)	(30,155)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.43	$ 0.47	$ 0.47	$ (0.04)	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.64	$ 5.30	$ 5.77	$ (0.66)	$ (0.47)

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

The $4.8 million increase in natural gas distribution gross profit was primarily due to a $17.7 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Mississippi, West Texas and Kentucky service areas.

These increases were partially offset by the following:

- $11.1 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.
- $1.6 million decrease due to an eight percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in the current year compared to last year in most of our service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $22.4 million primarily due to the following:

- $11.2 million increase in legal costs, primarily due to settlements.
- $10.6 million increase in employee-related costs.
- $8.4 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.
- $2.6 million increase in software maintenance costs.

These increases were partially offset by the following:

- $6.8 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.
- $2.9 million decrease due to the establishment of regulatory assets for pension and postretirement costs.

Miscellaneous income decreased $28.9 million primarily due to the absence of a $21.8 million pre-tax gain recognized in the prior year as a result of unwinding two Treasury locks ($13.6 million, net of tax) and a $10.0 million one-time donation to a donor advised fund in the current year.

Interest charges decreased $5.1 million compared to the prior year due primarily to the prepayment of our 5.125% $250 million senior notes in the fourth quarter of fiscal 2012, refinancing long-term debt at reduced interest rates and reducing commitment fees from decreasing the number of credit facilities and extending the length of their terms in fiscal 2011.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $11.3 million. Due to the completion of the sale of our Missouri, Iowa and Illinois service areas in the fiscal fourth quarter, the Company updated its analysis of the tax rate at which deferred taxes would reverse in the future to reflect the sale of these service areas. The updated analysis supported a reduction in the deferred tax rate which when applied to the balance of taxable income deferred to future periods resulted in a reduction of the Company's overall deferred tax liability.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

The $19.3 million increase in natural gas distribution gross profit primarily reflects a $38.6 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky and Kansas service areas.

These increases were partially offset by:

- $12.9 million decrease due to a seven percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in fiscal 2011 compared to the same period in fiscal 2010 in most of our service areas.
- $8.1 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $5.9 million, primarily due to the following:

- $10.0 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.4 million decrease in employee-related expenses.

These decreases were partially offset by:

- $5.4 million increase due to the absence of a state sales tax reimbursement received in fiscal 2010.
- $11.5 million increase in depreciation and amortization expense.
- $1.7 million increase in vehicles and equipment expense.

Net income for this segment for fiscal 2011 was also favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the fiscal years ended September 30, 2012, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In thousands)		
Mid-Tex	$142,755	$144,204	$134,655	$ (1,449)	$ 9,549
Kentucky/Mid-States	32,185	37,593	32,920	(5,408)	4,673
Louisiana	48,958	50,442	45,759	(1,484)	4,683
West Texas	27,875	29,686	33,509	(1,811)	(3,823)
Mississippi	27,369	26,338	26,441	1,031	(103)
Colorado-Kansas	23,898	25,920	24,543	(2,022)	1,377
Other	1,421	7,905	(976)	(6,484)	8,881
Total	$304,461	$322,088	$296,851	$(17,627)	$25,237

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 excess gas.

Our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$162,808	$125,973	$102,891	$36,835	$ 23,082
Third-party transportation	64,158	73,676	73,648	(9,518)	28
Storage and park and lend services	6,764	7,995	10,657	(1,231)	(2,662)
Other	13,621	11,729	15,817	1,892	(4,088)
Gross profit	247,351	219,373	203,013	27,978	16,360
Operating expenses	118,527	111,098	105,975	7,429	5,123
Operating income	128,824	108,275	97,038	20,549	11,237
Miscellaneous income (expense)	(1,051)	4,715	135	(5,766)	4,580
Interest charges	29,414	31,432	31,174	(2,018)	258
Income before income taxes	98,359	81,558	65,999	16,801	15,559
Income tax expense	35,300	29,143	24,513	6,157	4,630
Net income	$ 63,059	$ 52,415	$ 41,486	$10,644	$ 10,929
Gross pipeline transportation volumes — MMcf	640,732	620,904	634,885	19,828	(13,981)
Consolidated pipeline transportation volumes — MMcf	466,527	435,012	428,599	31,515	6,413

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

The $28.0 million increase in regulated transmission and storage gross profit compared to the prior year was primarily a result of the rate case that was finalized and became effective in May 2011 as well as the GRIP filings approved by the Railroad Commission of Texas (RRC) during fiscal 2011 and 2012. In May 2011, the RRC issued an order in the rate case of Atmos Pipeline — Texas that approved an annual operating income increase of $20.4 million. During fiscal 2011, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $12.6 million that went into effect in the fiscal fourth quarter. On April 10, 2012, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $14.7 million that went into effect with bills rendered on an after April 10, 2012.

Operating expenses increased $7.4 million primarily due to a $5.4 million increase in depreciation expense, resulting from higher investment in net plant.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $2.3 million associated with an update of the estimated tax rate at which deferred taxes would reverse in future periods after the completion of the sale of our Missouri, Illinois and Iowa assets. Net income for this segment for the prior year was favorably impacted by a $6.0 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks ($3.9 million, net of tax).

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

On April 18, 2011, the RRC issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity.

- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $16.4 million increase in regulated transmission and storage gross profit was attributable primarily to the following:

- $23.4 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $3.2 million increase associated with our most recent GRIP filing.

These increases were partially offset by the following:

- $4.8 million decrease due to the absence of the sale of excess gas, which occurred in the prior year.
- $4.4 million decrease due to a decline in throughput to our Mid-Tex Division primarily due to warmer than normal weather during fiscal 2011.

Operating expenses increased $5.1 million primarily due to the following:

- $4.6 million increase due to higher depreciation expense.
- $2.0 million increase due to the absence of a state sales tax reimbursement received in the prior year.

These increases were partially offset by the following:

- $0.8 million decrease related to lower levels of pipeline maintenance activities.
- $0.7 million decrease due to lower employee-related expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. These activities are reflected as gas delivery and related services in the table below.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. Most of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight. These activities are reflected as storage and transportation services in the table below.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas and demand fees paid to contract for storage capacity to offer more competitive pricing to those customers.

Further, natural gas market conditions, most notably the price of natural gas and the level of price volatility affect our nonregulated businesses. Natural gas prices and the level of volatility are influenced by a number of factors including, but not limited to, general economic conditions, the demand for natural gas in different parts of the country, the level of domestic natural gas production and the level of natural gas inventory levels.

Natural gas prices can influence:

- The demand for natural gas. Higher prices may cause customers to conserve or use alternative energy sources. Conversely, lower prices could cause customers such as electric power generators to switch from alternative energy sources to natural gas.
- Collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment.
- The level of borrowings under our credit facilities, which affects the level of interest expense recognized by this segment.

Natural gas price volatility can also influence our nonregulated business in the following ways:

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Price volatility also influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads.
- Increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Our nonregulated segment manages its exposure to natural gas commodity price risk through a combination of physical storage and financial instruments. Therefore, results for this segment include unrealized gains or losses on its net physical gas position and the related financial instruments used to manage commodity price risk. 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 generally 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.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$ 46,578	$ 58,990	$ 59,523	$(12,412)	$ (533)
Storage and transportation services	13,382	14,570	13,206	(1,188)	1,364
Other	3,737	5,265	5,347	(1,528)	(82)
	63,697	78,825	78,076	(15,128)	749
Asset optimization[1]	(558)	(3,424)	43,805	2,866	(47,229)
Total realized margins	63,139	75,401	121,881	(12,262)	(46,480)
Unrealized margins	(8,015)	(10,401)	(7,790)	2,386	(2,611)
Gross profit	55,124	65,000	114,091	(9,876)	(49,091)
Operating expenses, excluding asset impairment	36,886	39,113	44,147	(2,227)	(5,034)
Asset impairment	5,288	30,270	—	(24,982)	30,270
Operating income (loss)	12,950	(4,383)	69,944	17,333	(74,327)
Miscellaneous income	1,035	657	3,859	378	(3,202)
Interest charges	3,084	4,015	10,584	(931)	(6,569)
Income (loss) before income taxes	10,901	(7,741)	63,219	18,642	(70,960)
Income tax expense (benefit)	5,612	(209)	24,815	5,821	(25,024)
Net income (loss)	$ 5,289	$ (7,532)	$ 38,404	$ 12,821	$(45,936)
Gross nonregulated delivered gas sales volumes — MMcf	400,512	446,903	420,203	(46,391)	26,700
Consolidated nonregulated delivered gas sales volumes — MMcf	351,628	384,799	353,853	(33,171)	30,946
Net physical position (Bcf)	18.8	21.0	15.7	(2.2)	5.3

[1] Net of storage fees of $18.4 million, $15.2 million and $13.2 million.

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

Results for our nonregulated operations during fiscal 2012 were adversely influenced by continued unfavorable natural gas market conditions. Historically high natural gas storage levels from strong domestic natural gas production caused natural gas prices to remain relatively low during fiscal 2012. Additionally, we continued to experience compressed spot to forward spread values and basis differentials.

We anticipate these natural gas market conditions will continue for the foreseeable future. As a result, we anticipate that basis differentials will remain compressed and spot-to-forward price volatility will remain relatively low. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities for the foreseeable future to be more consistent with the performance we have experienced during the last two fiscal years.

Realized margins for gas delivery, storage and transportation services and other services were $63.7 million during the year ended September 30, 2012 compared with $78.8 million for the prior year. The decrease reflects the following:

- A nine percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A $0.02/Mcf decrease in gas delivery per-unit margins compared to the prior year primarily due to lower basis differentials resulting from increased natural gas supply and increased transportation costs.

Asset optimization margins increased $2.9 million from the prior year. The increase primarily reflects higher realized margins earned from the settlement of financial instruments used to hedge our natural gas inventory purchases, partially offset by increased storage fees associated with increased park and loan activity and a $1.7 million charge in the first fiscal quarter of the current year to write down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Unrealized margins increased $2.4 million in the current year compared to the prior year primarily due to the timing of year-over-year realized margins.

Operating expenses, excluding asset impairments decreased $2.2 million primarily due to lower employee-related expenses.

During the fourth quarter of fiscal 2012, we recorded a $5.3 million noncash charge to impair our natural gas gathering assets located in Kentucky. The charge reflected a reduction in the value of the project due to the current low natural gas price environment and management's decision to focus AEH's activities on its gas delivery, storage and transportation services. In the prior year, asset impairments included an asset impairment charge of $19.3 million related to our investment in our Fort Necessity storage project as well as an $11.0 million pre-tax impairment charge related to the write-off of certain natural gas gathering assets.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

Realized margins for gas delivery, storage and transportation services and other services were $78.8 million during the year ended September 30, 2011 compared with $78.1 million for the prior-year period. The increase primarily reflects the following:

- $1.4 million increase in margins from storage and transportation services, primarily attributable to new drilling projects in the Barnett Shale area.
- $0.6 million decrease in gas delivery and other services primarily due to lower per-unit margins partially offset by a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market. Per-unit margins were $0.13/Mcf in the current year compared with $0.14/Mcf in the prior year. The year-over-year decrease in per-unit margins reflects the impact of increased competition and lower basis spreads.

The $47.2 million decrease in realized asset optimization margins from the prior year primarily reflects the unfavorable impact of weak natural gas market fundamentals which provided fewer favorable trading opportunities.

Unrealized margins decreased $2.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.0 million primarily due to lower employee-related expenses and ad valorem taxes.

During fiscal 2011, our nonregulated segment recognized $30.3 million of noncash asset impairment charges associated with the two aforementioned projects.

Interest charges decreased $6.6 million primarily due to a decrease in intercompany borrowings.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility that expires February 1, 2013 to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds from the $350 million 30-year unsecured senior notes, which are expected to be issued in January 2013. We fixed the Treasury yield component of the interest cost associated with these anticipated senior notes at 4.07% by executing three Treasury lock agreements in August 2011. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2013.

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 such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 586,917	$ 582,844	$ 726,476	$ 4,073	$(143,632)
Investing activities	(609,260)	(627,386)	(542,702)	18,126	(84,684)
Financing activities	(44,837)	44,009	(163,025)	(88,846)	207,034
Change in cash and cash equivalents	(67,180)	(533)	20,749	(66,647)	(21,282)
Cash and cash equivalents at beginning of period	131,419	131,952	111,203	(533)	20,749
Cash and cash equivalents at end of period	$ 64,239	$ 131,419	$ 131,952	$(67,180)	$ (533)

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Fiscal Year ended September 30, 2012 compared with fiscal year ended September 30, 2011

For the fiscal year ended September 30, 2012, we generated operating cash flow of $586.9 million from operating activities compared with $582.8 million in the prior year. The year-over-year increase reflects changes in working capital offset by the $56.7 million increase in contributions made to our pension and postretirement plans during fiscal 2012.

Fiscal Year ended September 30, 2011 compared with fiscal year ended September 30, 2010

For the fiscal year ended September 30, 2011, we generated operating cash flow of $582.8 million from operating activities compared with $726.5 million in fiscal September 30, 2010. The year-over-year decrease reflects the absence of an $85 million income tax refund received in the prior year coupled with the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable 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 focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. 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.

In early fiscal 2010, two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, agreed to a program of installing, beginning in the first quarter of fiscal 2011, 100,000 steel service line replacements during fiscal 2011 and 2012, with approved recovery of the associated return, depreciation and taxes for lines replaced between October 1, 2010 and September 30, 2012. As of September 30, 2012, we had replaced 98,675 lines. Since October 1, 2010 we have spent $116.3 million on steel service line replacements.

For the fiscal year ended September 30, 2012, we incurred $732.9 million for capital expenditures compared with $623.0 million for the fiscal year ended September 30, 2011 and $542.6 million for the fiscal year ended September 30, 2010.

The $109.9 million increase in capital expenditures in fiscal 2012 compared to fiscal 2011 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and increased capital spending to increase the capacity on our Atmos Pipeline — Texas system. As a result of these projects, we anticipate capital expenditures will remain elevated during the next fiscal year.

The $80.4 million increase in capital expenditures in fiscal 2011 compared to fiscal 2010 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and the construction of a new customer contact center in Amarillo, Texas, partially offset by costs incurred in the prior fiscal year to relocate the company's information technology data center.

Cash flows from financing activities

For the fiscal year ended September 30, 2012, our financing activities used $44.8 million in cash, while financing activities for the fiscal year ended September 30, 2011 generated $44.0 million in cash compared with cash of $163.0 million used for the fiscal year ended September 30, 2010. Our significant financing activities for the fiscal years ended September 30, 2012, 2011 and 2010 are summarized as follows:

2012

During the fiscal year ended September 30, 2012, we:

- Paid $257.0 million for long-term debt repayments, including the early redemption of our $250 million 5.125% Senior notes that were scheduled to mature in January 2013.

- Borrowed $260 million under a short-term loan to finance the repayment of our $250 million 5.125% Senior notes.
- Borrowed a net $94.1 million under our short-term facilities, excluding the $260 million short-term loan used to finance the early redemption of our $250 million 5.125% Senior notes, to fund working capital needs.
- Paid $125.8 million in cash dividends, which reflected a payout ratio of 58 percent of net income.
- Paid $12.5 million for the repurchase of common stock as part of our share buyback program.
- Paid $5.2 million for the repurchase of equity awards.

2011

During the fiscal year ended September 30, 2011, we:

- Received $394.5 million net cash proceeds in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- Borrowed a net $83.3 million under our short-term facilities to fund working capital needs.
- Received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.
- Received $20.1 million cash in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- Received $7.8 million net proceeds related to the issuance of 0.3 million shares of common stock.
- Paid $360.1 million for scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011.
- Paid $124.0 million in cash dividends which reflected a payout ratio of 60 percent of net income.
- Paid $5.3 million for the repurchase of equity awards.

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under an accelerated share repurchase agreement.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that beginning in fiscal 2010 shares were purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

The following table shows the number of shares issued for the fiscal years ended September 30, 2012, 2011 and 2010:

	For the Fiscal Year Ended September 30		
	2012	2011	2010
Shares issued:			
Direct stock purchase plan	—	—	103,529
Retirement savings plan	—	—	79,722
1998 Long-term incentive plan	482,289	675,255	421,706
Outside directors stock-for-fee plan	2,375	2,385	3,382
Total shares issued	484,664	677,640	608,339

The decreased number of shares issued in fiscal 2012 compared with the number of shares issued in fiscal 2011 primarily reflects a decrease in the number of shares issued under our 1998 Long-Term Incentive Plan (LTIP), due to the exercise of a significant number of stock options during fiscal 2011. During fiscal 2012, we cancelled and retired 153,255 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares attributable to our share repurchase program, which are not included in the table above.

The increase in the number of shares issued in fiscal 2011 compared with the number of shares issued in fiscal 2010 primarily reflects an increased number of shares issued under our LTIP due to the exercise of a significant number of stock options during fiscal 2011. This increase was partially offset by the fact that we purchased shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During fiscal 2011, we cancelled and retired 169,793 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our 2010 accelerated share repurchase agreement, which are not included in the table above.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our LTIP. In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements.

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program collateralized by our $750 million unsecured credit facility and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $989 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature, which, if utilized, would increase borrowing capacity to $1.0 billion. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires on March 31, 2013, with $900 million available for issuance at September 30, 2012. We intend to file a new shelf registration statement with the SEC for at least $1.3 billion prior to the expiration of the current shelf.

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 environment in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (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+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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, 2012. Our debt covenants are described in Note 7 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2012 and 2011:

	September 30			
	2012		2011	
	(In thousands, except percentages)			
Short-term debt	$ 570,929	11.7%	$ 206,396	4.4%
Long-term debt	1,956,436	40.0%	2,208,551	47.3%
Shareholders' equity	2,359,243	48.3%	2,255,421	48.3%
Total capitalization, including short-term debt	$4,886,608	100.0%	$4,670,368	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.7 percent at September 30, 2012 and 2011. 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 continue to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2012.

	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]	$1,960,131	$ 131	$500,000	$250,000	$1,210,000
Short-term debt[1]	570,929	570,929	—	—	—
Interest charges[2]	1,434,549	123,572	223,346	192,960	894,671
Gas purchase commitments[3]	333,839	259,235	74,604	—	—
Capital lease obligations[4]	1,008	186	372	372	78
Operating leases[4]	180,991	17,571	33,155	29,633	100,632
Demand fees for contracted storage[5]	9,473	6,285	2,986	74	128
Demand fees for contracted transportation[6]	25,484	13,171	12,072	241	—
Financial instrument obligations[7]	94,587	85,381	9,206	—	—
Postretirement benefit plan contributions[8]	207,636	28,317	32,523	39,741	107,055
Uncertain tax positions (including interest)[9]	1,831	—	1,831	—	—
Total contractual obligations[10]	$4,820,458	$1,104,778	$890,095	$513,021	$2,312,564

(1) See Note 7 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, 2012.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our nonregulated segment. 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 nonregulated segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2012. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled. The table above excludes $0.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Georgia operations.

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

(9) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns.

(10) Total contractual obligations exclude pension plan contributions, which are discussed in Note 9. We anticipate contributing between $30 million and $40 million to these plans during fiscal 2013.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2012, AEH was committed to purchase 72.2 Bcf within one year, 29.0 Bcf within one to three years and 29.0 Bcf after three years under indexed contracts. AEH is committed to purchase 3.8 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $2.46 to $6.36 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 terms of individual contracts. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of natural gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under the terms of these contracts as of September 30, 2012 are reflected in the table above.

Risk Management Activities

As discussed above in our Critical Accounting Policies, we use financial instruments to mitigate commodity price risk and, periodically, to manage interest rate risk. We conduct risk management activities through our natural gas distribution and nonregulated 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 nonregulated segments, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

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

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2012 (in thousands):

Fair value of contracts at September 30, 2011	$(79,277)
Contracts realized/settled	(32,027)
Fair value of new contracts	4,782
Other changes in value	30,262
Fair value of contracts at September 30, 2012	$ (76,260)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2012, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2012				
	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	$(78,543)	$2,283	$—	$—	$(76,260)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(78,543)	$2,283	$—	$—	$(76,260)

The tables above include $0.1 million of current assets from risk management activities that are classified as assets held for sale and $0.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Georgia operations.

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the fiscal year ended September 30, 2012 (in thousands):

Fair value of contracts at September 30, 2011	$(25,050)
Contracts realized/settled	15,677
Fair value of new contracts	—
Other changes in value	(5,750)
Fair value of contracts at September 30, 2012	(15,123)
Netting of cash collateral	23,675
Cash collateral and fair value of contracts at September 30, 2012	$ 8,552

The fair value of our nonregulated segment's financial instruments at September 30, 2012, is presented below by time period and fair value source.

	Fair Value of Contracts at September 30, 2012				
	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	$(5,917)	$(9,222)	$16	$—	$(15,123)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(5,917)	$(9,222)	$16	$—	$(15,123)

Employee Benefits Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefits programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2006, we have experienced medical and prescription inflation of approximately six percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. We have changed the design of our health care plans to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in future years. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2013, we anticipate an approximate seven percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the implementation of the Health Care Reform Act.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2012, our total net periodic pension and other benefits costs was $69.2 million, compared with $56.6 million and $50.8 million for the fiscal years ended September 30, 2011 and 2010. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates were significantly lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. Our expected return on our pension plan assets was reduced to 7.75 percent due to historical experience and the current market projection of the target asset allocation. As a result, our fiscal 2012 pension and postretirement medical costs were higher than in the prior year.

The increase in total net periodic pension and other benefits costs during fiscal 2011 compared with fiscal 2010 primarily reflects the decrease in our discount rate at September 30, 2010, the measurement date for our fiscal 2011 pension and postretirement costs. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2010 measurement date, the interest rates were significantly higher than the interest rates at September 30, 2009, the measurement date used to determine our fiscal 2009 net periodic cost. Our expected return on our pension plan assets remained constant at 8.25 percent.

Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974 (ERISA). 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.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based on this valuation, we were required to contribute cash of $46.5 million to our pension plans during fiscal 2012. The need for this funding primarily reflects a decrease in the discount rate used to determine our obligations under our plans. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold.

During fiscal 2011, we were required to contribute cash of $0.9 million to our pension plans. The need for this funding reflected the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold. During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the PPA.

We contributed $22.1 million, $11.3 million and $11.8 million to our postretirement benefits plans for the fiscal years ended September 30, 2012, 2011 and 2010. 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 2013 and Beyond

As of September 30, 2012, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2013 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2011, the measurement date for our fiscal 2012 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2013 pension and benefit costs to 4.04 percent. We maintained the expected return on our pension plan assets at 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Due to the decrease in our discount rate, we expect our fiscal 2013 pension and postretirement medical costs to increase compared to fiscal 2012.

Based upon market conditions subsequent to September 30, 2012 the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $30 million and $40 million to the Plans in fiscal 2013. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing between $25 million and $30 million during fiscal 2013.

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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP have continued to earn benefits and interest allocations with no changes to their existing benefits.

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 nonregulated 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 nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 4 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

Natural gas distribution segment

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

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated 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, 2012 of 0.4 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.2 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, 2012 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 $5.8 million.

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

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term 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 $2.5 million during 2012.

ITEM 8. ***Financial Statements and Supplementary Data.***

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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

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2012 and 2011, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2012, 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), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2012, 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 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2012	September 30 2011
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,860,358	$6,607,552
Construction in progress	274,112	209,242
	7,134,470	6,816,794
Less accumulated depreciation and amortization	1,658,866	1,668,876
Net property, plant and equipment	5,475,604	5,147,918
Current assets		
Cash and cash equivalents	64,239	131,419
Accounts receivable, less allowance for doubtful accounts of $9,425 in 2012 and $7,440 in 2011	234,526	273,303
Gas stored underground	256,415	289,760
Other current assets	272,782	316,471
Total current assets	827,962	1,010,953
Goodwill and intangible assets	740,847	740,207
Deferred charges and other assets	451,262	383,793
	$7,495,675	$7,282,871
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2012 — 90,239,900 shares, 2011 — 90,296,482 shares	$ 451	$ 451
Additional paid-in capital	1,745,467	1,732,935
Accumulated other comprehensive loss	(47,607)	(48,460)
Retained earnings	660,932	570,495
Shareholders' equity	2,359,243	2,255,421
Long-term debt	1,956,305	2,206,117
Total capitalization	4,315,548	4,461,538
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	215,229	291,205
Other current liabilities	489,665	367,563
Short-term debt	570,929	206,396
Current maturities of long-term debt	131	2,434
Total current liabilities	1,275,954	867,598
Deferred income taxes	1,015,083	960,093
Regulatory cost of removal obligation	381,164	428,947
Deferred credits and other liabilities	507,926	564,695
	$7,495,675	$7,282,871

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,145,330	$2,470,664	$2,783,863
Regulated transmission and storage segment	247,351	219,373	203,013
Nonregulated segment	1,351,303	2,024,893	2,146,658
Intersegment eliminations	(305,501)	(428,495)	(472,474)
	3,438,483	4,286,435	4,661,060
Purchased gas cost			
Natural gas distribution segment	1,122,587	1,452,721	1,785,221
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,296,179	1,959,893	2,032,567
Intersegment eliminations	(304,022)	(426,999)	(470,864)
	2,114,744	2,985,615	3,346,924
Gross profit	1,323,739	1,300,820	1,314,136
Operating expenses			
Operation and maintenance	453,613	442,965	454,621
Depreciation and amortization	237,525	223,832	208,539
Taxes, other than income	181,073	177,767	187,143
Asset impairments	5,288	30,270	—
Total operating expenses	877,499	874,834	850,303
Operating income	446,240	425,986	463,833
Miscellaneous income (expense), net	(14,644)	21,184	(591)
Interest charges	141,174	150,763	154,188
Income from continuing operations before income taxes	290,422	296,407	309,054
Income tax expense	98,226	106,819	119,203
Income from continuing operations	192,196	189,588	189,851
Income from discontinued operations, net of tax ($10,066, $12,372 and $9,584)	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax ($3,519, $0 and $0)	6,349	—	—
Net income	$ 216,717	$ 207,601	$ 205,839
Basic earnings per share			
Income per share from continuing operations	$ 2.12	$ 2.08	$ 2.05
Income per share from discontinued operations	0.27	0.20	0.17
Net income per share — basic	$ 2.39	$ 2.28	$ 2.22
Diluted earnings per share			
Income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03
Income per share from discontinued operations	0.27	0.20	0.17
Net income per share — diluted	$ 2.37	$ 2.27	$ 2.20
Weighted average shares outstanding:			
Basic	90,150	90,201	91,852
Diluted	91,172	90,652	92,422

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock		Additional	Accumulated Other		
	Number of Shares	Stated Value	Paid-in Capital	Comprehensive Loss	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2009	92,551,709	$463	$1,791,129	$(20,184)	$ 405,353	$2,176,761
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net of tax of $1,025	—	—	—	1,745	—	1,745
Treasury lock agreements, net of tax of $1,193	—	—	—	2,030	—	2,030
Cash flow hedges, net of tax of $(4,452)	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income	—	—	—	—	207,601	207,601
Unrealized holding losses on investments, net of tax of $(953)	—	—	—	(1,647)	—	(1,647)
Treasury lock agreements, net of tax of $(16,850)	—	—	—	(28,689)	—	(28,689)
Cash flow hedges, net of tax of $3,355	—	—	—	5,248	—	5,248
Total comprehensive income						182,513
Repurchase of common stock	(375,468)	(2)	2	—	—	—
Repurchase of equity awards	(169,793)	(1)	(5,298)	—	—	(5,299)
Cash dividends ($1.36 per share)	—	—	—	—	(124,011)	(124,011)
Common stock issued:						
Direct stock purchase plan	—	—	(54)	—	—	(54)
1998 Long-term incentive plan	675,255	3	13,886	—	—	13,889
Employee stock-based compensation	—	—	9,958	—	—	9,958
Outside directors stock-for-fee plan	2,385	—	77	—	—	77
Balance, September 30, 2011	90,296,482	451	1,732,935	(48,460)	570,495	2,255,421
Comprehensive income:						
Net income	—	—	—	—	216,717	216,717
Unrealized holding gains on investments, net of tax of $1,881	—	—	—	3,103	—	3,103
Treasury lock agreements, net of tax of $(5,388)	—	—	—	(10,116)	—	(10,116)
Cash flow hedges, net of tax of $5,029	—	—	—	7,866	—	7,866
Total comprehensive income						217,570
Repurchase of common stock	(387,991)	(2)	(12,533)	—	—	(12,535)
Repurchase of equity awards	(153,255)	—	(5,219)	—	—	(5,219)
Cash dividends ($1.38 per share)	—	—	—	—	(125,796)	(125,796)
Common stock issued:						
Direct stock purchase plan	—	—	(65)	—	—	(65)
1998 Long-term incentive plan	482,289	2	12,519	—	(484)	12,037
Employee stock-based compensation	—	—	17,752	—	—	17,752
Outside directors stock-for-fee plan	2,375	—	78	—	—	78
Balance, September 30, 2012	90,239,900	$451	$1,745,467	$(47,607)	$ 660,932	$2,359,243

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended September 30		
	2012	2011	2010
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 216,717	$ 207,601	$ 205,839
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	5,288	30,270	—
Gain on sale of discontinued operations	(9,868)	—	—
Depreciation and amortization:			
Charged to depreciation and amortization	246,093	233,155	216,960
Charged to other accounts	484	228	173
Deferred income taxes	104,319	117,353	196,731
Stock-based compensation	19,222	11,586	12,655
Debt financing costs	8,147	9,438	11,908
Other	(493)	(961)	(1,245)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	32,578	(96)	(40,401)
Decrease in gas stored underground	28,417	27,737	54,014
(Increase) decrease in other current assets	20,989	(38,048)	(18,387)
(Increase) decrease in deferred charges and other assets	(50,055)	(53,519)	14,886
Increase (decrease) in accounts payable and accrued liabilities	(64,234)	23,904	58,069
Increase (decrease) in other current liabilities	7,889	(57,495)	(48,992)
Increase in deferred credits and other liabilities	21,424	71,691	64,266
Net cash provided by operating activities	586,917	582,844	726,476
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(732,858)	(622,965)	(542,636)
Proceeds from the sale of discontinued operations	128,223	—	—
Other, net	(4,625)	(4,421)	(66)
Net cash used in investing activities	(609,260)	(627,386)	(542,702)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase in short-term debt	354,141	83,306	54,268
Net proceeds from issuance of long-term debt	—	394,466	—
Settlement of Treasury lock agreements	—	20,079	—
Unwinding of Treasury lock agreements	—	27,803	—
Repayment of long-term debt	(257,034)	(360,131)	(131)
Cash dividends paid	(125,796)	(124,011)	(124,287)
Repurchase of common stock	(12,535)	—	(100,450)
Repurchase of equity awards	(5,219)	(5,299)	(1,191)
Issuance of common stock	1,606	7,796	8,766
Net cash provided by (used in) financing activities	(44,837)	44,009	(163,025)
Net increase (decrease) in cash and cash equivalents	(67,180)	(533)	20,749
Cash and cash equivalents at beginning of year	131,419	131,952	111,203
Cash and cash equivalents at end of year	$ 64,239	$ 131,419	$ 131,952

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other non-regulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three 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
Atmos Energy Kentucky/Mid-States Division	Georgia[1], Kentucky, Tennessee, Virginia[1]
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

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

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

On August 1, 2012, we completed the divesture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. On August 8, 2012, we entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. The results of these operations have been separately reported as discontinued operations.

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

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

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; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

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, unbilled revenues, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements 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. Accounting principles generally accepted in the United States require 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.

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, 2012 and 2011 included the following:

	September 30	
	2012	2011
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$296,160	$254,666
Merger and integration costs, net	5,754	6,242
Deferred gas costs	31,359	33,976
Regulatory cost of removal asset	10,500	8,852
Rate case costs	4,661	4,862
Deferred franchise fees	2,714	379
Risk-based replacement program costs	5,370	—
APT annual adjustment mechanism	4,539	—
Other	7,262	3,919
	$368,319	$312,896
Regulatory liabilities:		
Deferred gas costs	$ 23,072	$ 8,130
Regulatory cost of removal obligation	459,688	464,025
APT annual adjustment mechanism	—	6,654
Other	5,637	7,371
	$488,397	$486,180

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of September 30, 2012, we had deferred $5.4 million associated with the requirements of this rule.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. We elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $7.6 million, which is recorded in "Pension and postretirement benefit costs" in the regulatory assets table above. Of this amount, $4.2 million represented a reduction to operation and maintenance expense during fiscal 2012.

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, 2012, 2011 and 2010, we recognized $0.5 million, $0.5 million and $0.4 million in amortization expense related to these costs.

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

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, 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 cost adjustment mechanisms. Purchased gas cost 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 cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our nonregulated activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2012, 2011 and 2010, we included unrealized gains (losses) on open contracts of $(8.0) million, $(10.4) million and $(7.8) million as a component of nonregulated revenues.

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

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

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

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our nonregulated segment to conduct their operations. The average cost method is used for all our regulated operations, 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. Our nonregulated segment utilizes the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $2.6 million, $1.7 million and $3.9 million was capitalized in 2012, 2011 and 2010.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.6 percent, 3.6 percent and 3.5 percent for the fiscal years ended September 30, 2012, 2011 and 2010.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 50 years.

Asset retirement obligations — 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, 2012 and 2011, we recorded asset retirement obligations of $10.5 million and $14.0 million. Additionally, we recorded $4.2 million and $5.4 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 natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot reasonably estimate the fair value of this obligation.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 2012, we recorded a pre-tax noncash impairment loss of $5.3 million related to our gathering systems in Kentucky. In fiscal 2011, we recorded pre-tax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering systems in Kentucky. See Note 5 for further details.

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

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

Marketable securities — As of September 30, 2012 and 2011, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, 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 an individual investment by investment 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 investment is written down to its estimated fair value.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our natural gas distribution and nonregulated segments and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses and are discussed in Note 4.

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

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

Financial Instruments Associated with Commodity Price Risk

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

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

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

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

Our nonregulated segment also utilizes master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2012 and 2011, the Company netted $23.7 million and $28.8 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, typically when we plan to issue new long-term debt or to refinance existing long-term debt. Prior to fiscal 2012, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

During fiscal 2012, we began using interest rate swaps to mitigate interest rate risk. We entered into an interest rate swap associated with our $260 million short-term financing facility through December 27, 2012. Due to the short-term nature of the swap and the related financing facility, we did not designate the interest rate swap as a hedge. Gains and losses associated with the swap are reported as a component of interest expense.

Additionally, in October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred will be reported as a component of interest expense.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices), as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. As of September 30, 2012 our Master Trust owned one real estate investment that qualifies as a Level 3 fair value measurement. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

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. Our measurement date is September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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

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

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

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

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2012 and 2011, consisted of the following unrealized gains (losses):

	September 30	
	2012	2011
	(In thousands)	
Unrealized holding gains on investments	$ 5,661	$ 2,558
Treasury lock agreements	(44,273)	(34,157)
Cash flow hedges	(8,995)	(16,861)
	$(47,607)	$(48,460)

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and reasonably estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Subsequent events — We have evaluated subsequent events from the September 30, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. Except as disclosed in Note 4, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — During the year ended September 30, 2012, three new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard indefinitely defers the effective date for new presentation requirements related to reclassifications of items from accumulated other comprehensive income, which were scheduled to be effective for interim and annual periods beginning after December 15, 2011. The third standard allows companies to apply qualitative impairment tests to indefinite-lived intangibles if certain criteria are met and is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2012.

3. Goodwill

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2012:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
	(In thousands)			
Balance as of September 30, 2011	$572,908	$132,381	$34,711	$740,000
Deferred tax adjustments on prior acquisitions[1]	642	41	—	683
Balance as of September 30, 2012	$573,550	$132,422	$34,711	$740,683

(1) During the preparation of the fiscal 2012 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $0.7 million.

4. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2012 and 2011:

	Natural Gas Distribution	Nonregulated	Total
		(In thousands)	
September 30, 2012[3]			
Assets from risk management activities, current[1]	$ 6,934	$ 17,773	$ 24,707
Assets from risk management activities, noncurrent	2,283	—	2,283
Liabilities from risk management activities, current[1]	(85,366)	(15)	(85,381)
Liabilities from risk management activities, noncurrent	—	(9,206)	(9,206)
Net assets (liabilities)	$(76,149)	$ 8,552	$(67,597)
September 30, 2011[4]			
Assets from risk management activities, current[2]	$ 843	$ 17,501	$ 18,344
Assets from risk management activities, noncurrent	998	—	998
Liabilities from risk management activities, current[2]	(11,916)	(3,537)	(15,453)
Liabilities from risk management activities, noncurrent	(67,862)	(10,227)	(78,089)
Net assets (liabilities)	$(77,937)	$ 3,737	$(74,200)

(1) Includes $23.7 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting arrangements and the remaining $17.8 million is classified as current risk management assets.

(2) Includes $28.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

(3) The September 30, 2012 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Georgia operations. At September 30, 2012, assets and liabilities held for sale included $0.1 million of current assets from risk management activities and $0.3 million of current liabilities from risk management activities.

(4) The September 30, 2011 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations. At September 30, 2011, assets and liabilities held for sale included $1.3 million of current liabilities from risk management activities.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $4.78 per Mcf. We have not designated these financial instruments as hedges.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To provide these services, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 63 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

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

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2012, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.4 Bcf.

Interest Rate Risk Management Activities

We have periodically managed interest rate risk by entering into financial instruments to fix the Treasury yield component of the interest cost associated with anticipated financings. Prior to fiscal 2012, we used Treasury locks to mitigate interest rate risk; however, in the fourth quarter of fiscal 2012 we started utilizing interest rate swaps and forward starting interest rate swaps to manage this risk.

In August 2012, we redeemed $250 million of senior notes originally maturing on January 15, 2013 through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received from the issuance of $350 million 30-year unsecured notes anticipated to occur in January 2013. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

In the fourth quarter of fiscal 2012 we entered into an interest rate swap to fix the LIBOR component of our $260 million short-term financing facility through December 27, 2012. Due to the short-term nature of the swap and the related financing facility we did not designate the interest rate swap as a hedge. Gains and losses associated with the swap are reported as a component of interest expense.

In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred will be reported as a component of interest expense.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and is being recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter of fiscal 2011.

In prior years, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extends through fiscal 2041.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and income statements.

As of September 30, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(22,650)
	Cash Flow	—	35,300
	Not designated	24,185	49,155
		24,185	61,805

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of September 30, 2012 and 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $23.7 million and $28.8 million of cash held on deposit in margin accounts as of September 30, 2012 and 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2012				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 19,301	$ 19,301
Noncurrent commodity contracts	Deferred charges and other assets	—	1,923	1,923
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(85,040)	(23,787)	(108,827)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(4,999)	(4,999)
Total		(85,040)	(7,562)	(92,602)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets[1]	7,082	98,393	105,475
Noncurrent commodity contracts	Deferred charges and other assets	2,283	60,932	63,215
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[2]	(585)	(99,824)	(100,409)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(67,062)	(67,062)
Total		8,780	(7,561)	1,219
Total Financial Instruments		$(76,260)	$(15,123)	$ (91,383)

[1] Other current assets not designated as hedges in our natural gas distribution segment include $0.1 million related to risk management assets that were classified as assets held for sale at September 30, 2012.

[2] Other current liabilities not designated as hedges in our natural gas distribution segment include $0.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

[1] Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2012, 2011 and 2010, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $23.1 million, $24.8 million and $51.8 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2012, 2011 and 2010 is presented below.

	Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands)		
Commodity contracts	$30,266	$16,552	$34,650
Fair value adjustment for natural gas inventory designated as the hedged item	(5,797)	9,824	19,867
Total impact on purchased gas cost	$24,469	$26,376	$54,517
The impact on purchased gas cost is comprised of the following:			
Basis ineffectiveness	$ 1,170	$ 803	$ (1,272)
Timing ineffectiveness	23,299	25,573	55,789
	$24,469	$26,376	$54,517

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the year ended September 30, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the years ended September 30, 2011 and 2010.

Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2012, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2012			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$—	$(62,678)	$(62,678)
Loss arising from ineffective portion of commodity contracts	—	—	(1,369)	(1,369)
Total impact on purchased gas cost	—	—	(64,047)	(64,047)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,009)	—	—	(2,009)
Total impact from cash flow hedges	$(2,009)	$—	$(64,047)	$(66,056)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$ —	$(28,430)	$(28,430)
Loss arising from ineffective portion of commodity contracts	—	—	(1,585)	(1,585)
Total impact on purchased gas cost	—	—	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total impact from cash flow hedges	$19,348	$6,000	$(30,015)	$ (4,667)

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$—	$(44,809)	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	—	(2,717)	(2,717)
Total impact on purchased gas cost	—	—	(47,526)	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$—	$(47,526)	$(50,204)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Fiscal Year Ended September 30	
	2012	2011
	(In thousands)	
Decrease in fair value:		
Treasury lock agreements	$(11,458)	$(12,720)
Forward commodity contracts	(30,366)	(12,096)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	1,342	(15,969)
Forward commodity contracts	38,232	17,344
Total other comprehensive loss from hedging, net of tax(1)	$ (2,250)	$(23,441)

(1) Utilizing an income tax rate ranging from approximately 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2012. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into in August 2011 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2013	$(1,276)	$(7,171)	$(8,447)
2014	(1,276)	(1,908)	(3,184)
2015	606	10	616
2016	776	46	822
2017	675	28	703
Thereafter	10,222	—	10,222
Total(1)	$ 9,727	$(8,995)	$ 732

(1) Utilizing an income tax rate ranging from approximately 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2012, 2011 and 2010 was an increase (decrease) in revenue of $(2.5) million, $(1.4) million and $15.4 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 9.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(2)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2012
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 9,365	$ —	$ —	$ 9,365
Nonregulated segment(1)	714	179,835	—	(162,776)	17,773
Total financial instruments	714	189,200	—	(162,776)	27,138
Hedged portion of gas stored underground	67,192	—	—	—	67,192
Available-for-sale securities					
Money market funds	—	1,634	—	—	1,634
Registered investment companies	40,212	—	—	—	40,212
Bonds	—	22,552	—	—	22,552
Total available-for-sale securities	40,212	24,186	—	—	64,398
Total assets	$108,118	$213,386	$ —	$(162,776)	$158,728
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 85,625	$ —	$ —	$ 85,625
Nonregulated segment(1)	4,563	191,109	—	(186,451)	9,221
Total liabilities	$ 4,563	$276,734	$ —	$(186,451)	$ 94,846

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[2]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[4]	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment[1]	8,502	104,156	—	(95,156)	17,502
Total financial instruments	8,502	105,997	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$92,886	$122,186	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment[1]	9,324	128,384	—	(123,943)	13,765
Total liabilities	$ 9,324	$209,502	$ —	$(123,943)	$ 94,883

(1) Certain of the nonregulated segment's financial instruments were reclassified from Level 1 to Level 2 upon further evaluation.

(2) Our Level 2 measurements consist of over-the-counter options and swaps, which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds, which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2012 we had $23.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting agreements and the remaining $17.8 million is classified as current risk management assets.

(4) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2012:				
Domestic equity mutual funds	$25,779	$8,183	$ —	$33,962
Foreign equity mutual funds	5,568	682	—	6,250
Bonds	22,358	196	(2)	22,552
Money market funds	1,634	—	—	1,634
	$55,339	$9,061	$ (2)	$64,398
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633

At September 30, 2012 and 2011, our available-for-sale securities included $41.8 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans as discussed in Note 9. At September 30, 2012 we maintained investments in bonds that have contractual maturity dates ranging from October 2012 through July 2016.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Atmos Gathering Company (AGC) owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we were to be paid from future production generated from the assets.

As discussed in Note 13, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, in fiscal 2011, we performed an impairment assessment of these assets and determined the assets to be impaired at which time we recorded a pre-tax noncash impairment loss of approximately $11 million. Due to developments in the fourth quarter of fiscal 2012, including further operating losses as a result of the lawsuit and management's decision to focus our nonregulated operations on delivered gas and transportation services, we performed an impairment assessment of these assets and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $0.5 million and recorded a pre-tax noncash impairment loss of approximately $5.3 million. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired.

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pre-tax noncash impairment loss to write off substantially all of our investment in the project.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of September 30, 2012:

	September 30, 2012
	(In thousands)
Carrying Amount	$1,960,131
Fair Value	$2,426,434

6. Discontinued Operations

On August 1, 2012, we completed the sale of substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $128 million, pursuant to an asset purchase agreement executed on May 12, 2011. In connection with the sale, we recognized a pre-tax gain of approximately $9.9 million.

On August 8, 2012, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur in late fiscal 2013.

As required under generally accepted accounting principles, the operating results of our Georgia, Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents statement of income data related to discontinued operations in our Georgia, Missouri, Illinois and Iowa service areas.

	Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Operating revenues	$114,703	$141,227	$128,630
Purchased gas cost	62,902	83,537	77,825
Gross profit	51,801	57,690	50,805
Operating expenses	24,174	27,362	25,202
Operating income	27,627	30,328	25,603
Other nonoperating income (expense)	611	57	(31)
Income from discontinued operations before income taxes	28,238	30,385	25,572
Income tax expense	10,066	12,372	9,584
Income from discontinued operations	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax	6,349	—	—
Net income from discontinued operations	$ 24,521	$ 18,013	$ 15,988

The following table presents balance sheet data related to assets held for sale. At September 30, 2012 assets held for sale include assets and liabilities associated with our Georgia operations. At September 30, 2011 assets held for sale include assets and liabilities associated with our Missouri, Iowa and Illinois operations. On August 1, 2012 we completed the sale of our Missouri, Iowa and Illinois operations.

	September 30, 2012	September 30, 2011
	(In thousands)	
Net plant, property & equipment	$142,865	$127,577
Gas stored underground	4,688	11,931
Other current assets	6,931	786
Deferred charges and other assets	87	277
Assets held for sale	$154,571	$140,571
Accounts payable and accrued liabilities	$ 2,114	$ 1,917
Other current liabilities	3,776	4,877
Regulatory cost of removal	3,257	10,498
Deferred credits and other liabilities	2,426	1,153
Liabilities held for sale	$ 11,573	$ 18,445

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

7. Debt

Long-term debt

Long-term debt at September 30, 2012 and 2011 consisted of the following:

	2012	2011
	(In thousands)	
Unsecured 10% Notes, redeemed December 2011	$ —	$ 2,303
Unsecured 5.125% Senior Notes, redeemed August 2012	—	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Medium term notes		
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term notes due in installments through 2013	131	262
Total long-term debt	1,960,131	2,212,565
Less:		
Original issue discount on unsecured senior notes and debentures	(3,695)	(4,014)
Current maturities	(131)	(2,434)
	$1,956,305	$2,206,117

Our unsecured 10% notes were paid on their maturity date on December 31, 2011 and were not replaced. Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility that expires February 1, 2013 to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received through the issuance of $350 million 30-year unsecured senior notes, which are expected to be issued in January 2013. In connection with the redemption, we paid a $4.6 million make-whole premium in accordance with the terms of the indenture and the Senior Notes and accrued interest at the time of redemption. In accordance with regulatory requirements, the premium will be deferred and will be recognized over the life of the new unsecured senior notes expected to be issued in January 2013.

Short-term debt

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Prior to the fourth quarter of fiscal 2012, we financed our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $985 million of working capital funding. On July 25, 2012, we increased the borrowing capacity of our $10 million revolving credit facility to $14 million. As a result of these changes, we have $989 million of working capital funding at September 30, 2012. At September 30, 2012 and 2011, there was $310.9 million and $206.4 million outstanding under our commercial paper program. As of September 30, 2012 our commercial paper had maturities of approximately two months with interest rates of

0.43 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $789 million of working capital funding. The first facility is a five-year $750 million unsecured facility, expiring May 2016, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to two percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. This facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At September 30, 2012, there were no borrowings under this facility, but we had $310.9 million of commercial paper outstanding leaving $439.1 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2012, there were no borrowings outstanding under this facility.

The third facility is a $14 million committed revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate plus 1.5 percent. The borrowing capacity of this facility was increased from $10 million on July 25, 2012. At September 30, 2012, there were no borrowings outstanding under this credit facility; however, letters of credit totaling $11.5 million had been issued under the facility at September 30, 2012, which reduced the amount available by a corresponding amount.

The availability of funds under these 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 each of these 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, 2012, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH. This facility replaced the former $350 million intercompany facility. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012. There was $211.5 million outstanding under this facility at September 30, 2012.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2012, there were no borrowings outstanding under this credit facility. However, at September 30, 2012, AEM letters of credit totaling $11.5 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 $138.5 million at September 30, 2012.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.74 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2012, AEM's net working capital was $136.2 million and its tangible net worth was $150.8 million.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012. There were no borrowings outstanding under this facility at September 30, 2012.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires on March 31, 2013, with $900 million available for issuance at September 30, 2012. We intend to file a new shelf registration statement with the SEC for at least $1.3 billion prior to the expiration of the current shelf.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, 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.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of September 30, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2012 were as follows (in thousands):

2013	$ 131
2014	—
2015	500,000
2016	—
2017	250,000
Thereafter	1,210,000
	$1,960,131

8. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 our Board of Directors approved a program authorizing the repurchase of up to five million shares of common stock over a five-year period. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. The program may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. As of September 30, 2012, a total of 387,991 shares had been repurchased for an aggregate value of $12.5 million.

Stock-Based Compensation Plans

Total stock-based compensation expense was $19.2 million, $11.6 million and $12.7 million for the fiscal years ended September 30, 2012, 2011 and 2010, 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, time-lapse restricted stock units, 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.

As of September 30, 2012, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2012, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 1,949,088 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

Employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividend equivalents that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividend equivalents on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2012, 2011 and 2010:

	2012		2011		2010	
	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	1,264,142	$29.56	1,293,960	$27.28	1,295,841	$27.23
Granted	532,711	33.44	491,345	33.10	551,278	29.07
Vested	(494,308)	26.32	(464,321)	27.21	(493,957)	29.24
Forfeited	(39,963)	29.83	(56,842)	27.56	(59,202)	26.54
Nonvested at end of year	1,262,582	$32.46	1,264,142	$29.56	1,293,960	$27.28

As of September 30, 2012, there was $10.1 million of total unrecognized compensation cost related to nonvested time-lapse restricted shares and restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.6 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2012, 2011 and 2010 was $13.0 million, $12.6 million and $14.4 million.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2012		2011		2010	
	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	86,766	$22.16	434,962	$22.46	611,227	$21.88
Granted	—	—	—	—	—	—
Exercised	(76,672)	21.79	(348,196)	22.54	(176,265)	20.44
Forfeited	—	—	—	—	—	—
Expired	—	—	—	—	—	—
Outstanding at end of year[1]	10,094	$24.95	86,766	$22.16	434,962	$22.46
Exercisable at end of year[2]	10,094	$24.95	86,766	$22.16	434,962	$22.46

(1) The weighted-average remaining contractual life for outstanding options was 1.7 years, 1.7 years, and 1.6 years for fiscal years 2012, 2011 and 2010. The aggregate intrinsic value of outstanding options was $0.03 million, $0.3 million and $1.6 million for fiscal years 2012, 2011 and 2010.

(2) The weighted-average remaining contractual life for exercisable options was 1.7 years, 1.7 years and 1.6 years for fiscal years 2012, 2011 and 2010. The aggregate intrinsic value of exercisable options was $0.03 million, $0.3 million and $1.6 million for the fiscal years 2012, 2011 and 2010.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2012, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price
$21.23 to $22.99	2,164	0.4	$21.23
$23.00 to $25.95	7,930	2.1	$25.95
$21.23 to $25.95	10,094	1.7	$24.95

	Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$1,671	$7,848	$3,604
Income tax benefit from stock option exercises	$ 401	$1,010	$ 547
Total intrinsic value of options exercised	$ 256	$1,263	$ 239

As of September 30, 2012, there was no unrecognized compensation cost related to nonvested stock options.

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

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

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

Other Discretionary Compensation Plans

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

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure 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 that cover substantially all employees. These plans are discussed in further detail below.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2012				
Unrecognized transition obligation	$ —	$ —	$ 1,709	$ 1,709
Unrecognized prior service cost	(232)	—	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$186,818	$43,995	$57,700	$288,513
September 30, 2011				
Unrecognized transition obligation	$ —	$ —	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	—	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$182,113	$30,654	$41,899	$254,666

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2012, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to 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 credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account is credited with interest on the employee's prior year account balance. A special grandfather benefit also applied 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 are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension

Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2012 and 2011, we contributed $46.5 million and $0.9 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2010, we did not make any contributions to our pension plans. Based upon market conditions subsequent to September 30, 2012, the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $30 million and $40 million to the Plans in fiscal 2013. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds.

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

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

The following table presents asset allocation information for the Master Trust as of September 30, 2012 and 2011.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2012	Actual Allocation September 30 2011
Domestic equities	35%-55%	42.6%	40.4%
International equities	10%-20%	13.9%	13.6%
Fixed income	10%-30%	18.6%	21.3%
Company stock	5%-15%	12.0%	13.5%
Other assets	5%-15%	12.9%	11.2%

At September 30, 2012 and 2011, the Plan held 1,169,700 shares of our common stock, which represented 12.0 percent and 13.5 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.6 million during fiscal 2012 and 2011.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 September 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 September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2012	2011	2012	2011	2010
Discount rate	4.04%	5.05%	5.05%	5.39%[1]	5.52%
Rate of compensation increase	3.50%	3.50%	3.50%	4.00%	4.00%
Expected return on plan assets	7.75%	7.75%	7.75%	8.25%	8.25%

[1] The discount rate for the Pension Account Plan increased from 5.39% to 5.68% effective January 1, 2011 due to a curtailment gain recorded in fiscal 2011.

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Accumulated benefit obligation	$ 468,440	$ 414,489
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 429,432	$ 407,536
Service cost	15,084	14,384
Interest cost	21,568	22,264
Actuarial loss	46,197	12,944
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	—
Curtailments	—	(162)
Benefit obligation at end of year	480,031	429,432
Change in plan assets:		
Fair value of plan assets at beginning of year	280,204	301,708
Actual return on plan assets	48,656	5,154
Employer contributions	46,534	876
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	—
Fair value of plan assets at end of year	343,144	280,204
Reconciliation:		
Funded status	(136,887)	(149,228)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(136,887)	$(149,228)

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net periodic pension cost for the Plans for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 15,084	$ 14,384	$ 13,499
Interest cost	21,568	22,264	20,870
Expected return on assets	(21,474)	(24,817)	(25,280)
Amortization of prior service cost	(141)	(429)	(960)
Recognized actuarial loss	14,451	9,498	9,290
Curtailment gain	—	(40)	—
Net periodic pension cost	$ 29,488	$ 20,860	$ 17,419

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2012 and 2011. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2. Assets at September 30, 2012 include $7.7 million that will be transferred to the purchaser of our Missouri, Illinois and Iowa operations during the first quarter of fiscal 2013. In addition to the assets shown below, the Master Trust had net accounts receivable of $0.5 million and $0.4 million at September 30, 2012 and 2011 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks — domestic equities	$114,799	$ —	$ —	$114,799
Money market funds	—	21,010	—	21,010
Registered investment companies:				
Domestic funds	19,984	—	—	19,984
International funds	36,714	—	—	36,714
Common/collective trusts — domestic funds	—	52,155	—	52,155
Government securities:				
Mortgage-backed securities	—	19,509	—	19,509
U.S. treasuries	7,597	487	—	8,084
Corporate bonds	—	35,960	—	35,960
Limited partnerships	140	41,786	—	41,926
Real estate	—	—	155	155
Total investments at fair value	$179,234	$170,907	$155	$350,296

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks — domestic equities	$ 94,336	$ —	$ —	$ 94,336
Money market funds	—	9,383	—	9,383
Registered investment companies:				
Domestic funds	12,921	—	—	12,921
International funds	27,528	—	—	27,528
Common/collective trusts — domestic funds	—	40,096	—	40,096
Government securities				
Mortgage-backed securities	—	18,860	—	18,860
U.S. treasuries	4,946	47	—	4,993
Corporate bonds	—	33,636	—	33,636
Limited partnerships	113	37,693	—	37,806
Real estate	—	—	200	200
Total investments at fair value	$139,844	$139,715	$200	$279,759

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. These assets decreased during the year ended September 30, 2012 due to the sale of a parcel of real estate during fiscal 2012.

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 (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 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 September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2012	2011	2012	2011	2010
Discount rate	4.04%	5.05%	5.05%	5.39%	5.52%
Rate of compensation increase	3.50%	3.50%	3.50%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Accumulated benefit obligation	$ 121,815	$ 104,363
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 112,115	$ 108,919
Service cost	2,108	2,768
Interest cost	5,142	5,825
Actuarial loss	15,459	2,140
Benefits paid	(4,638)	(7,537)
Benefit obligation at end of year	130,186	112,115
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	4,638	7,537
Benefits paid	(4,638)	(7,537)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(130,186)	(112,115)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(130,186)	$(112,115)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2012 and 2011, assets held in the rabbi trusts consisted of available-for-sale securities of $41.8 million and $38.3 million, which are included in our fair value disclosures in Note 5.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net periodic pension cost for the supplemental plans for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$2,108	$ 2,768	$2,476
Interest cost	5,142	5,825	5,224
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	—	187
Recognized actuarial loss	2,118	2,239	1,999
Net periodic pension cost	$9,368	$10,832	$9,886

Estimated Future Benefit Payments

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

	Pension Plans	Supplemental Plans
	(In thousands)	
2013	$ 38,800	$31,108
2014	35,551	13,453
2015	33,953	7,658
2016	33,536	4,680
2017	32,740	7,385
2018-2022	156,231	41,830

Postretirement Benefits

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

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Atmos Retiree Medical Plan. Starting on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Atmos Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional cost.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of ERISA. 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 $28.3 million to our postretirement benefits plan during fiscal 2013.

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2012 and 2011.

	Actual Allocation September 30	
Security Class	**2012**	**2011**
Diversified investment funds	97.0%	96.8%
Cash and cash equivalents	3.0%	3.2%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 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 September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2011, 2010 and 2009. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2012	**2011**	**2012**	**2011**	**2010**
Discount rate	4.04%	5.05%	5.05%	5.39%	5.52%
Expected return on plan assets	4.70%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	8.00%	8.00%	8.00%	7.50%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2019	2018	2018	2016	2015

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 263,694	$ 228,234
Service cost	16,353	14,403
Interest cost	13,861	12,813
Plan participants' contributions	3,649	2,892
Actuarial loss	28,815	17,966
Benefits paid	(13,197)	(13,046)
Subsidy payments	—	432
Divestitures	(4,860)	—
Benefit obligation at end of year	308,315	263,694
Change in plan assets:		
Fair value of plan assets at beginning of year	53,065	53,033
Actual return on plan assets	12,912	(1,500)
Employer contributions	22,139	11,254
Plan participants' contributions	3,649	2,892
Benefits paid	(13,197)	(13,046)
Subsidy payments	—	432
Divestitures	(1,496)	—
Fair value of plan assets at end of year	77,072	53,065
Reconciliation:		
Funded status	(231,243)	(210,629)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(231,243)	$(210,629)

Net periodic postretirement cost for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands)		
Components of net periodic postretirement cost:			
Service cost	$16,353	$14,403	$13,439
Interest cost	13,861	12,813	12,071
Expected return on assets	(2,607)	(2,727)	(2,460)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	(1,450)
Recognized actuarial loss	2,648	347	374
Net periodic postretirement cost	$30,316	$24,897	$23,485

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 1,426	$ (1,287)
Effect on postretirement benefit obligation	$21,736	$(18,866)

We are currently recovering other postretirement benefits costs through our regulated rates under accrual accounting as prescribed by accounting principles generally accepted in the United States 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, our West Texas, Mid-Tex and Mississippi Divisions as well as our Kansas jurisdiction and Atmos Pipeline – Texas or have been included in a rate case and not disallowed. Management believes that this accounting method 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.

The following tables set forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2012 and 2011. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2. Assets at September 30, 2012 include $1.5 million that will be transferred to the purchaser of our Missouri, Illinois and Iowa operations during the first quarter of fiscal 2013.

	Assets at Fair Value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$2,360	$—	$ 2,360
Registered investment companies:				
Domestic funds	7,756	—	—	7,756
International funds	68,452	—	—	68,452
Total investments at fair value	$76,208	$2,360	$—	$78,568

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,707	$—	$ 1,707
Registered investment companies:				
Domestic funds	3,506	—	—	3,506
International funds	47,852	—	—	47,852
Total investments at fair value	$51,358	$1,707	$—	$53,065

Estimated Future Benefit Payments

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

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2013	$ 28,317	$ 3,696	$—	$ 32,013
2014	15,174	4,487	—	19,661
2015	17,349	5,251	—	22,600
2016	19,221	6,128	—	25,349
2017	20,520	7,083	—	27,603
2018-2022	107,055	48,114	—	155,169

Defined Contribution Plans

As of September 30, 2012, 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 Holdings, LLC 401K Profit-Sharing Plan (the AEH 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into the Retirement Savings Plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $10.5 million, $10.2 million, and $9.8 million for fiscal years 2012, 2011 and 2010. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code and applicable Treasury regulations. No discretionary contributions were made for fiscal years 2012, 2011 or 2010. At September 30, 2012 and 2011, the Retirement Savings Plan held 4.9 percent and 4.5 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH 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 75 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 four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 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 AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.2 million, $1.3 million and $1.3 million for fiscal years 2012, 2011 and 2010.

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, 2012 and 2011:

	September 30	
	2012	2011
	(In thousands)	
Billed accounts receivable	$177,953	$216,145
Unbilled revenue	42,694	48,006
Other accounts receivable	23,304	16,592
Total accounts receivable	243,951	280,743
Less: allowance for doubtful accounts	(9,425)	(7,440)
Net accounts receivable	$234,526	$273,303

Other current assets

Other current assets as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Assets from risk management activities	$ 24,707	$ 18,344
Deferred gas costs	31,359	33,976
Taxes receivable	1,291	9,215
Current deferred tax asset	27,091	76,725
Prepaid expenses	17,114	22,499
Current portion of leased assets receivable	168	2,013
Materials and supplies	5,872	4,113
Assets held for sale	154,571	140,571
Other	10,609	9,015
Total	$272,782	$316,471

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As discussed in Note 6, assets and liabilities related to our Georgia operations are classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2012. On August 1, 2012, we completed the divesture of our operations in Missouri, Illinois and Iowa. Assets and liabilities related to Missouri, Illinois and Iowa were classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2012 and 2011:

	September 30	
	2012	2011
	(In thousands)	
Production plant	$ 5,020	$ 7,412
Storage plant	232,260	198,422
Transmission plant	1,185,007	1,126,509
Distribution plant	4,680,877	4,496,263
General plant	717,568	737,850
Intangible plant	39,626	41,096
	6,860,358	6,607,552
Construction in progress	274,112	209,242
	7,134,470	6,816,794
Less: accumulated depreciation and amortization	(1,658,866)	(1,668,876)
Net property, plant and equipment	$ 5,475,604	$ 5,147,918

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Marketable securities	$ 64,398	$ 52,633
Regulatory assets	334,551	278,920
Deferred financing costs	35,101	35,149
Assets from risk management activities	2,283	998
Other	14,929	16,093
Total	$451,262	$383,793

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other current liabilities

Other current liabilities as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Customer credit balances and deposits	$100,926	$106,743
Accrued employee costs	37,675	38,558
Deferred gas costs	23,072	8,130
Accrued interest	34,451	37,557
Liabilities from risk management activities	85,381	15,453
Taxes payable	64,319	57,853
Pension and postretirement obligations	39,625	33,036
Regulatory cost of removal accrual	78,525	35,078
Liabilities held for sale	11,573	18,445
Other	14,118	16,710
Total	$489,665	$367,563

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Postretirement obligations	$221,231	$202,709
Retirement plan obligations	235,965	236,227
Customer advances for construction	12,937	13,967
Regulatory liabilities	5,638	13,823
Asset retirement obligation	10,394	13,574
Liabilities from risk management activities	9,206	78,089
Other	12,555	6,306
Total	$507,926	$564,695

11. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities), we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	2012	2011	2010
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$192,196	$189,588	$189,851
Less: Income from continuing operations allocated to participating securities	793	1,980	1,943
Income from continuing operations available to common shareholders	$191,403	$187,608	$187,908
Basic weighted average shares outstanding	90,150	90,201	91,852
Income from continuing operations per share — Basic	$ 2.12	$ 2.08	$ 2.05
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$ 24,521	$ 18,013	$ 15,988
Less: Income from discontinued operations allocated to participating securities	101	188	164
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Basic weighted average shares outstanding	90,150	90,201	91,852
Income from discontinued operations per share — Basic	$ 0.27	$ 0.20	$ 0.17
Net income per share — Basic	$ 2.39	$ 2.28	$ 2.22
Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$191,403	$187,608	$187,908
Effect of dilutive stock options and other shares	4	4	5
Income from continuing operations available to common shareholders	$191,407	$187,612	$187,913
Basic weighted average shares outstanding	90,150	90,201	91,852
Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from continuing operations per share — Diluted	$ 2.10	$ 2.07	$ 2.03
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Basic weighted average shares outstanding	90,150	90,201	91,852
Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from discontinued operations per share — Diluted	$ 0.27	$ 0.20	$ 0.17
Net income per share — Diluted	$ 2.37	$ 2.27	$ 2.20

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2012, 2011 and 2010.

12. Income Taxes

The components of income tax expense from continuing operations for 2012, 2011 and 2010 were as follows:

	2012	2011	2010
		(In thousands)	
Current			
Federal	$ 631	$ (13,298)	$ (70,884)
State	6,888	6,841	6,849
Deferred			
Federal	103,971	107,950	172,690
State	(13,237)	5,498	10,831
Investment tax credits	(27)	(172)	(283)
	$ 98,226	$106,819	$119,203

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2012, 2011 and 2010 are set forth below:

	2012	2011	2010
		(In thousands)	
Tax at statutory rate of 35%	$101,648	$103,743	$108,169
Common stock dividends deductible for tax reporting	(2,096)	(1,930)	(1,785)
Penalties	66	2,292	104
Recognition (settlement) of uncertain tax positions	1,831	(4,950)	—
State taxes (net of federal benefit)	(5,958)	8,109	11,493
Other, net	2,735	(445)	1,222
Income tax expense	$ 98,226	$106,819	$119,203

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2012 and 2011 are presented below:

	2012	2011
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 7,906	$ 10,327
Customer advances	4,721	5,271
Nonqualified benefit plans	48,513	43,924
Postretirement benefits	62,802	62,274
Treasury lock agreements	25,448	20,060
Unamortized investment tax credit	14	120
Tax net operating loss and credit carryforwards	164,419	95,293
Difference between book and tax on mark to market accounting	2,342	8,039
Other, net	7,223	3,529
Total deferred tax assets	323,388	248,837
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,254,698)	(1,108,063)
Pension funding	(32,812)	(7,533)
Gas cost adjustments	(21,806)	(13,570)
Cost expensed for tax purposes and capitalized for book purposes	(2,065)	(3,039)
Total deferred tax liabilities	(1,311,381)	(1,132,205)
Net deferred tax liabilities	$ (987,993)	$ (883,368)
Deferred credits for rate regulated entities	$ 140	$ 325

At September 30, 2012, we had $10.1 million of federal alternative minimum tax credit carryforwards, $143.2 million of federal net operating loss carryforwards, $10.6 million of state net operating loss carryforwards and $0.5 million of state tax credits. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2016 and 2030. The state tax credits will begin to expire in 2018.

At September 30, 2012, we had recorded liabilities associated with uncertain tax positions totaling $1.8 million. The realization of these tax benefits would reduce our income tax expense by approximately $1.8 million.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $13.6 million. Due to the completion of the sale of our Missouri, Iowa and Illinois service areas in the fiscal fourth quarter, the Company updated its analysis of the tax rate at which deferred taxes would reverse in the future to reflect the sale of these service areas. The updated analysis supported a reduction in the deferred tax rate which when applied to the balance of taxable income deferred to future periods resulted in a reduction of the Company's overall deferred tax liability.

At September 30, 2010, we had accrued liabilities associated with uncertain tax positions totaling $6.7 million. During the fiscal year ended September 30, 2011, the IRS completed its audit of fiscal years 2005-2007. All uncertain tax positions were effectively settled upon completion of the audit. As a result of the settlement, we reduced our unrecognized tax benefits by $6.7 million in the second quarter of fiscal 2011. Income tax expense was reduced by $5.0 million in the second quarter due to the realization of the tax positions which were previously uncertain.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.01 million, $0.01 million and $0.5 million related to penalty and interest expenses during the fiscal years ended September 30, 2012, 2011 and 2010.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2007.

13. Commitments and Contingencies

Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals (Court), appealing the verdict of the trial court. The appellees in this case subsequently filed their appellees' brief with the Court on January 16, 2012, with our reply brief being filed with the Court on March 19, 2012. Oral arguments were held in the case on August 27, 2012; however, the Court has yet to render a decision.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, *Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles*, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss. Since that time, we have been engaged in discovery activities in this case.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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, Tennessee and Keokuk, Iowa, 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. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa and the United States Environmental Protection Agency.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2012, AEH was committed to purchase 72.2 Bcf within one year, 29.0 Bcf within one to three years and 29.0 Bcf after three years under indexed contracts. AEH is committed to purchase 3.8 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from \$2.46 to \$6.36 per Mcf. Purchases under these contracts totaled \$978.8 million, \$1,498.6 million and \$1,562.8 million for 2012, 2011 and 2010.

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 and fixed prices. The estimated commitments under these contracts as of September 30, 2012 are as follows (in thousands):

2013	\$259,235
2014	74,604
2015	—
2016	—
2017	—
Thereafter	—
	\$333,839

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2012 are as follows (in thousands):

2013	$19,456
2014	10,554
2015	4,504
2016	278
2017	37
Thereafter	128
	$34,957

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division agreed to a program of installing 100,000 replacements through September 30, 2012, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 98,675 lines for a cost of $116.3 million as of September 30, 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

14. Leases

Capital and Operating Leases

We have entered into operating leases for office and warehouse space, vehicles and heavy equipment used in our operations. The remaining lease terms range from one to 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 and $1.3 million at September 30, 2012 and 2011. Accumulated depreciation for these capital leases totaled $0.9 and $0.9 million at September 30, 2012 and 2011. 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, 2012 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2013	$ 186	$ 17,571
2014	186	17,215
2015	186	15,940
2016	186	15,036
2017	186	14,597
Thereafter	78	100,632
Total minimum lease payments	1,008	$180,991
Less amount representing interest	286	
Present value of net minimum lease payments	$ 722	

Consolidated lease and rental expense amounted to $33.6 million, $35.5 million and $36.7 million for fiscal 2012, 2011 and 2010.

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, primarily consisting of letters of credit and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2012, 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. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2012 and 2011.

	September 30, 2012	September 30, 2011
Investment grade	60%	54%
Non-investment grade	40%	46%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2012. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment(1)	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 4	$ 4
Non-investment grade counterparties	—	—	—
	$—	$ 4	$ 4

(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 fiscal 2012, 2011 and 2010 are presented below.

	2012	2011	2010
		(In thousands)	
Cash paid for interest	$150,606	$157,976	$161,925
Cash received for income taxes	$ (432)	$ (8,329)	$ (63,677)

There were no significant noncash investing and financing transactions during fiscal 2012, 2011 and 2010. All cash flows and noncash activities related to our commodity financial instruments 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 over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in nine states. In addition, we transport natural gas for others through our distribution system.

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

We operate the Company through the following three segments:

- The *natural gas distribution 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.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

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, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,144,376	$ 92,604	$1,201,503	$ —	$3,438,483
Intersegment revenues	954	154,747	149,800	(305,501)	—
	2,145,330	247,351	1,351,303	(305,501)	3,438,483
Purchased gas cost	1,122,587	—	1,296,179	(304,022)	2,114,744
Gross profit	1,022,743	247,351	55,124	(1,479)	1,323,739
Operating expenses					
Operation and maintenance	353,879	71,521	29,697	(1,484)	453,613
Depreciation and amortization	202,026	31,438	4,061	—	237,525
Taxes, other than income	162,377	15,568	3,128	—	181,073
Asset impairments	—	—	5,288	—	5,288
Total operating expenses	718,282	118,527	42,174	(1,484)	877,499
Operating income	304,461	128,824	12,950	5	446,240
Miscellaneous income (expense)	(12,657)	(1,051)	1,035	(1,971)	(14,644)
Interest charges	110,642	29,414	3,084	(1,966)	141,174
Income from continuing operations before income taxes	181,162	98,359	10,901	—	290,422
Income tax expense	57,314	35,300	5,612	—	98,226
Income from continuing operations	123,848	63,059	5,289	—	192,196
Income from discontinued operations, net of tax	18,172	—	—	—	18,172
Gain on sale of discontinued operations, net of tax	6,349	—	—	—	6,349
Net income	$ 148,369	$ 63,059	$ 5,289	$ —	$ 216,717
Capital expenditures	$ 546,818	$175,768	$ 10,272	$ —	$ 732,858

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,469,781	$ 87,141	$1,729,513	$ —	$4,286,435
Intersegment revenues	883	132,232	295,380	(428,495)	—
	2,470,664	219,373	2,024,893	(428,495)	4,286,435
Purchased gas cost	1,452,721	—	1,959,893	(426,999)	2,985,615
Gross profit	1,017,943	219,373	65,000	(1,496)	1,300,820
Operating expenses					
Operation and maintenance	341,758	70,401	32,308	(1,502)	442,965
Depreciation and amortization	193,642	25,997	4,193	—	223,832
Taxes, other than income	160,455	14,700	2,612	—	177,767
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	695,855	111,098	69,383	(1,502)	874,834
Operating income (loss)	322,088	108,275	(4,383)	6	425,986
Miscellaneous income	16,242	4,715	657	(430)	21,184
Interest charges	115,740	31,432	4,015	(424)	150,763
Income (loss) from continuing operations before income taxes	222,590	81,558	(7,741)	—	296,407
Income tax expense (benefit)	77,885	29,143	(209)	—	106,819
Income (loss) from continuing operations	144,705	52,415	(7,532)	—	189,588
Income from discontinued operations, net of tax	18,013	—	—	—	18,013
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ —	$ 207,601
Capital expenditures	$ 496,899	$118,452	$ 7,614	$ —	$ 622,965

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,782,993	$ 97,023	$1,781,044	$ —	$4,661,060
Intersegment revenues	870	105,990	365,614	(472,474)	—
	2,783,863	203,013	2,146,658	(472,474)	4,661,060
Purchased gas cost	1,785,221	—	2,032,567	(470,864)	3,346,924
Gross profit	998,642	203,013	114,091	(1,610)	1,314,136
Operating expenses					
Operation and maintenance	349,465	72,249	34,517	(1,610)	454,621
Depreciation and amortization	182,097	21,368	5,074	—	208,539
Taxes, other than income	170,229	12,358	4,556	—	187,143
Total operating expenses	701,791	105,975	44,147	(1,610)	850,303
Operating income	296,851	97,038	69,944	—	463,833
Miscellaneous income (expense)	1,132	135	3,859	(5,717)	(591)
Interest charges	118,147	31,174	10,584	(5,717)	154,188
Income from continuing operations before income taxes	179,836	65,999	63,219	—	309,054
Income tax expense	69,875	24,513	24,815	—	119,203
Income from continuing operations	109,961	41,486	38,404	—	189,851
Income from discontinued operations, net of tax	15,988	—	—	—	15,988
Net income	$ 125,949	$ 41,486	$ 38,404	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 8,986	$ —	$ 542,636

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

	2012	2011	2010
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,351,479	$1,535,887	$1,751,186
Commercial	587,651	685,380	775,714
Industrial	71,960	96,636	101,814
Public authority and other	54,334	68,676	69,944
Total gas sales revenues	2,065,424	2,386,579	2,698,658
Transportation revenues	53,924	57,331	56,539
Other gas revenues	25,028	25,871	27,796
Total natural gas distribution revenues	2,144,376	2,469,781	2,782,993
Regulated transmission and storage revenues	92,604	87,141	97,023
Nonregulated revenues	1,201,503	1,729,513	1,781,044
Total operating revenues	$3,438,483	$4,286,435	$4,661,060

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at September 30, 2012 and 2011 by segment is presented in the following tables.

	September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,432,017	$ 979,443	$ 64,144	$ —	$5,475,604
Investment in subsidiaries	747,496	—	(2,096)	(745,400)	—
Current assets					
Cash and cash equivalents	12,787	—	51,452	—	64,239
Assets from risk management activities	6,934	—	17,773	—	24,707
Other current assets	546,187	11,788	404,097	(223,056)	739,016
Intercompany receivables	636,557	—	—	(636,557)	—
Total current assets	1,202,465	11,788	473,322	(859,613)	827,962
Intangible assets	—	—	164	—	164
Goodwill	573,550	132,422	34,711	—	740,683
Noncurrent assets from risk management activities	2,283	—	—	—	2,283
Deferred charges and other assets	417,893	24,353	6,733	—	448,979
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,359,243	$ 328,161	$419,335	$ (747,496)	$2,359,243
Long-term debt	1,956,305	—	—	—	1,956,305
Total capitalization	4,315,548	328,161	419,335	(747,496)	4,315,548
Current liabilities					
Current maturities of long-term debt	—	—	131	—	131
Short-term debt	782,719	—	—	(211,790)	570,929
Liabilities from risk management activities	85,366	—	15	—	85,381
Other current liabilities	526,089	12,478	90,116	(9,170)	619,513
Intercompany payables	—	584,578	51,979	(636,557)	—
Total current liabilities	1,394,174	597,056	142,241	(857,517)	1,275,954
Deferred income taxes	789,288	220,647	5,148	—	1,015,083
Noncurrent liabilities from risk management activities	—	—	9,206	—	9,206
Regulatory cost of removal obligation	381,164	—	—	—	381,164
Deferred credits and other liabilities	495,530	2,142	1,048	—	498,720
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

18. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2012:				
Operating revenues				
Natural gas distribution	$ 676,113[1]	$ 871,067[2]	$ 315,634[3]	$282,516
Regulated transmission and storage	56,759	58,037	67,073	65,482
Nonregulated	444,176	370,763	256,250	280,114
Intersegment eliminations	(93,054)	(74,358)	(62,543)	(75,546)
	1,083,994	1,225,509	576,414	552,566
Gross profit	355,392[1]	425,787[2]	293,171[3]	249,389
Operating income	139,471[1]	202,432[2]	81,546[3]	22,791
Income (loss) from continuing operations	62,384	102,084	28,014	(286)
Income from discontinued operations	6,123	7,027	3,118	1,904
Gain on sale of discontinued operations	—	—	—	6,349
Net income	68,507	109,111	31,132	7,967
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ —
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share — basic	$ 0.75	$ 1.20	$ 0.34	$ 0.09
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ —
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share — diluted	$ 0.75	$ 1.20	$ 0.34	$ 0.09

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2011:				
Operating revenues				
Natural gas distribution	$ 687,426[4]	$1,052,291[5]	$ 396,584[6]	$334,363[7]
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,117,226	1,556,374	833,168	779,667
Gross profit	357,582[4]	444,466[5]	261,612[6]	237,160[7]
Operating income	150,773[4]	204,624[5]	31,394[6]	39,195[7]
Income (loss) from continuing operations	68,208	124,293	(3,150)	237
Income from discontinued operations	5,789	7,916	2,584	1,724
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.06	0.09	$ 0.03	$ 0.02
Net income (loss) per share — basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.06	$ 0.09	$ 0.03	$ 0.02
Net income (loss) per share — diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

(1) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.2 million, $7.5 million and $4.9 million, which were not previously reported as discontinued operations.

(2) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.9 million, $8.5 million and $5.9 million, which were not previously reported as discontinued operations.

(3) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.4 million, $5.6 million and $3.2 million, which were not previously reported as discontinued operations.

(4) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $16.0 million, $7.1 million and $4.5 million, which were not previously reported as discontinued operations.

(5) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $25.1 million, $9.2 million and $6.6 million, which were not previously reported as discontinued operations.

(6) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $10.4 million, $5.2 million and $2.7 million, which were not previously reported as discontinued operations.

(7) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.6 million, $4.9 million and $2.1 million, which were not previously reported as discontinued operations.

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2012, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ KIM R. COCKLIN	/s/ BRET J. ECKERT
Kim R. Cocklin President and Chief Executive Officer	Bret J. Eckert Senior Vice President and Chief Financial Officer

November 12, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2012, 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, 2012, 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, 2012 and 2011, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012 of Atmos Energy Corporation and our report dated November 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

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, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***Other Information.***

Not applicable.

PART III

ITEM 10. ***Directors, Executive Officers and Corporate Governance.***

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2012, 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	65	15	Executive Chairman of the Board
Kim R. Cocklin	61	6	President and Chief Executive Officer
Louis P. Gregory	57	12	Senior Vice President and General Counsel
Michael E. Haefner	52	4	Senior Vice President, Human Resources
Bret J. Eckert	45	—	Senior Vice President and Chief Financial Officer

Robert W. Best was named Executive Chairman of the Board on October 1, 2010. From March 1997 through September 2008, Mr. Best served the Company as Chairman of the Board, President and Chief Executive Officer. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

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

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

Bret J. Eckert joined the Company in June 2012 as Senior Vice President, and on October 1, 2012 he was appointed Chief Financial Officer. Prior to joining the Company, Mr. Eckert was an Assurance Partner with Ernst & Young LLP where he developed extensive accounting and financial experience in the natural gas industry over his 22-year career.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit

Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance."

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

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 10.6(a) through 10.13(e) are management contracts or compensatory plans or arrangements.

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/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and Chief Financial Officer

Date: November 12, 2012

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin and Bret J. Eckert, 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/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 12, 2012
/s/ BRET J. ECKERT Bret J. Eckert	Senior Vice President and Chief Financial Officer	November 12, 2012
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 12, 2012
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 12, 2012
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 12, 2012
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 12, 2012
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 12, 2012
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 12, 2012
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 12, 2012
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 12, 2012
/s/ RICHARD A. SAMPSON Richard A. Sampson	Director	November 12, 2012
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 12, 2012
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 12, 2012
/s/ RICHARD WARE II Richard Ware II	Director	November 12, 2012

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2012

	Balance at beginning of period	Additions: Charged to cost & expenses	Additions: Charged to other accounts	Deductions	Balance at end of period
		(In thousands)			
2012					
Allowance for doubtful accounts	$ 7,440	$8,901	$—	$6,916[1]	$ 9,425
2011					
Allowance for doubtful accounts	$12,701	$2,201	$—	$7,462[1]	$ 7,440
2010					
Allowance for doubtful accounts	$11,478	$7,694	$—	$6,471[1]	$12,701

[1] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession	
2.1(a)	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
2.1(b)	Amendment No. 1 to Asset Purchase Agreement	
2.2	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Georgia) Corp. as Buyer, dated as of August 8, 2012	Exhibit 2.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders, Including Indentures	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6 3/4% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(c)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(d)	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)
4.7(e)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(f)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Material Contracts	
10.1	Term Loan Credit Agreement, dated as of September 27, 2012 among Atmos Energy Corporation, the lenders from time to time party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, U.S. Bank National Association, as Syndication Agent and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agent	Exhibit 10.1 to Form 8-K dated September 27, 2012 (File No. 1-10042)
10.2	Revolving Credit Agreement, dated as of May 2, 2011 among Atmos Energy Corporation, the Lenders from time to time parties thereto, The Royal Bank of Scotland plc as Administrative Agent, Crédit Agricole Corporate and Investment Bank as Syndication Agent, Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A. as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated May 2, 2011 (File No. 1-10042)
10.3(a)	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and The Royal Bank of Scotland plc, as co-syndication agent and a bank; and Natixis, New York Branch, Crédit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3(b)	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010, (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.4(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	Exhibit 10.6(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.4(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	Exhibit 10.6(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.5(a)	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
10.5(b)	Guaranty of Algonquin Power & Utilities Corp. dated August 8, 2012	Exhibit 10.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(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)
10.7(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)
10.8(a)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	Exhibit 10.14 to Form 10-K for fiscal year ended September 30, 2011 (File No. 1-10042)
10.8(b)*	Amendment No 1 to the Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
10.9(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	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)
10.9(e)*	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)
10.10(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)
10.10(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)
10.10(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)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2011 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(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)
10.13(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
12	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	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2012
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
	Interactive Data File	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

* 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.