ATMOS ENERGY CORP
Form 10-K
November 13, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended September 30, 2013
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 þ 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 þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
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 þ 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 þ 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 þ
The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2013, was $3,816,801,052.
As of November 8, 2013, the registrant had 90,912,251 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 5, 2014 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
AOCI	Accumulated Other Comprehensive Income
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
CFTC	Commodity Futures Trading Commission
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.
GAAP	Generally Accepted Accounting Principles
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
PPA	Pension Protection Act of 2006
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

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PART I

The terms “we,” “our,” “us”, “Atmos Energy” and the “Company” refer to Atmos Energy Corporation and its subsidiaries, unle 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 eight 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.

Over the last two fiscal years, we have sold our natural gas distribution operations in four states to streamline our regulated operations. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers, and in August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers.

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

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our business exceptionally well
- invest in our people and infrastructure
- enhance our culture.

We have delivered excellent shareholder value by growing our earnings and increasing our dividends for over 25 consecutive years. Over the last five years, 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.

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Natural Gas Distribution Segment Overview

Our natural gas distribution segment is comprised of our six regulated natural gas distribution divisions. This segment represents approximately 65 percent of our consolidated net income. The following table summarizes key information about these divisions, presented in order of total rate base. See Note 16 in the consolidated financial statements for a description of the completed sales of our Missouri, Illinois, Iowa and Georgia service areas. 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, 2013, we held 998 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.

Division	Service Areas	Communities Served	Customer Meters
Mid-Tex	Texas, including the Dallas/Fort Worth Metroplex	550	1,560,409
Kentucky/Mid-States	Kentucky	230	179,708
	Tennessee		123,590
	Virginia		20,358
Louisiana	Louisiana	300	342,187
West Texas	Amarillo, Lubbock, Midland	80	293,802
Mississippi	Mississippi	110	255,730
Colorado-Kansas	Colorado	170	99,654
	Kansas		136,542

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. Historically, this generally has resulted 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. However, rate design changes implemented during the first quarter of fiscal 2013 in our Mid-Tex and West Texas Divisions should change this trend. The rate design approved in these regulatory proceedings includes an increase to the customer base charge and a decrease in the consumption charge applied to customer usage. The effect of this change in rate design allows our rates to be more closely aligned with the natural gas distribution industry standard rate design. In addition, we anticipate these divisions, which represent approximately 50 percent of the operating income for our natural gas distribution segment, will earn their operating income more ratably over the fiscal year as they are now less dependent on customer consumption.

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. 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 distribution 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 distribution companies 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.

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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.

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 Debt/ Equity Ratio	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	50/50	11.80%
Atmos Pipeline — Texas — GRIP	Texas	05/07/2013	979,324	9.36%	N/A	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	50/50	10.25%
	Kansas	09/01/2012	160,075	(2)	(2)	(2)
Kentucky/Mid-States	Kentucky	06/01/2010	221,340(3)	(2)	(2)	(2)
	Tennessee	11/08/2012	201,359	8.28%	49/51	10.10%
	Virginia	11/23/2009	36,861	8.48%	51/49	9.50% - 10.50%
Louisiana	Trans LA	04/01/2013	105,527	7.94%	52/48	10.00% - 10.80%
	LGS	07/01/2013	298,642	8.08%	52/48	10.40%
Mid-Tex Cities	Texas	12/04/2012	1,512,986(4)	8.57%	48/52	10.50%
Mid-Tex — Dallas	Texas	06/01/2013	1,619,429(4)	8.35%	48/52	10.10%
Mississippi	Mississippi	11/01/2012	287,646	8.04%	49/51	9.64%
West Texas(5)	Texas	10/01/2012	271,590	(2)	(2)	(2)

Division	Jurisdiction	Bad Debt Rider(6)	Annual Rate Mechanism	Infrastructure Mechanism	Performance-Based Rate Program(7)	WNA Period
Atmos Pipeline — Texas	Texas	No	No	Yes	N/A	N/A
Colorado-Kansas	Colorado	Yes(8)	No	Yes	No	N/A
	Kansas	Yes	No	Yes	No	October-May
Kentucky/Mid-States	Kentucky	Yes	No	Yes	Yes	November-April
	Tennessee	Yes	No	No	Yes	October-April
	Virginia	Yes	No	Yes	No	January-December
Louisiana	Trans LA	No	Yes	No	No	December-March
	LGS	No	Yes	No	No	December-March
Mid-Tex Cities	Texas	Yes	Yes	Yes	No	November-April
Mid-Tex — Dallas	Texas	Yes	Yes	Yes	No	November-April
Mississippi	Mississippi	No	Yes	No	Yes	November-April
West Texas(5)	Texas	Yes	No	Yes	No	October-May

(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) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $36.6 million included in the October 2012 PRP surcharge. A total of $36.6 million of the Kentucky rate base amount was granted in the annual PRP filing with an effective date of October 1, 2012, an authorized rate of return of 8.74 percent and an authorized

return on equity of 10.50 percent.

(4) The Mid-Tex Rate Base amounts for the Mid-Tex Cities and Dallas areas represent “system-wide”, or 100 percent, of the Mid-Tex Division’s rate base.

(5) On October 2, 2012, a rate case settlement was approved by the Texas Railroad Commission (RRC) that combined the former Amarillo, Lubbock and West Texas jurisdictions into a single "West Texas" jurisdiction.
(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 distribution companies to minimize purchased gas costs by allowing the companies and its customers to share the purchased gas costs savings.
(8) The Company and Commission Staff have agreed to roll the recovery of the gas portion of uncollectible accounts back into base rates as part of the current rate proceeding.

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 2013 were Anadarko Energy Services Company, BP Energy Company, ConocoPhillips Company, Devon Gas Services, L.P., Enterprise Products Operating LLC, Iberdrola Energy Services, LLC, Sequent Energy Management, L.P., Targa Gas Marketing LLC, Tenaska Marketing Ventures, 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 2013 was on January 15, 2013, when sales to customers reached approximately 3.1 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 35 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.

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 (APT). APT is 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. It 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 excess gas. This segment represents approximately 30 percent of our consolidated operations.

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.

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Nonregulated Segment Overview

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation, and represent approximately five percent of our consolidated net income.

AEH's primary business is to buy, sell and deliver natural gas at competitive prices to approximately 1,000 customers located primarily in the Midwest and Southeast areas of the United States. AEH accomplishes this objective by aggregating and purchasing gas supply, arranging transportation and storage logistics and effectively managing commodity price risk.

AEH also earns storage and transportation demand fees primarily from our regulated natural gas distribution operations in Louisiana and Kentucky. These demand fees are subject to regulatory oversight and are renewed periodically.

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 69 percent of our natural gas distribution gross margin.
- Accelerated recovery of capital for approximately 74 percent of our natural gas distribution gross margin.
- Enhanced rate design that allows us to defer certain elements of our cost of service until they are included in rates, such as depreciation, ad valorem taxes and pension costs.
- WNA mechanisms in seven 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, 2013, 2012 and 2011 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 $98.1 million, $30.7 million and $72.4 million, became effective in fiscal 2013, 2012 and 2011, as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2013	2012	2011
	(In thousands)		
Infrastructure programs	$30,936	$19,172	$15,033
Annual rate filing mechanisms	9,152	7,044	35,216
Rate case filings	56,700	4,309	20,502
Other ratemaking activity	1,322	167	1,675

	$98,110	$30,692	$72,426

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Additionally, the following ratemaking efforts were initiated during fiscal 2013 but had not been completed as of September 30, 2013:

Division	Rate Action	Jurisdiction	Operating Income Requested (In thousands)
Colorado-Kansas	Rate Case[1]	Colorado	$10,891
Kentucky/Mid-States	Rate Case	Kentucky	13,133
	PRP[2]	Kentucky	2,493
	PRP[2]	Virginia	213
Mid-Tex Division	GRIP[3]	Railroad Commission - Environs	768
	RRM[4]	Mid-Tex Cities	17,077
Mississippi	Stable Rate Filing[5]	Mississippi	—
			$44,575

(1) This rate case seeks a multi-year step increase in annual operating income of $4.5 million on January 1, 2014, $2.9 million on July 1, 2014 and $3.5 million on July 1, 2015.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Kentucky and Virginia PRPs were implemented on October 1, 2013.

(3) The Gas Reliability Infrastructure Program (GRIP) surcharge relates to replacing aging infrastructure as well as other changes in net plant. The surcharge is calculated on a system-wide basis, but is only filed with the Railroad Commission for unincorporated areas served by the Mid-Tex Division.

(4) The Rate Review Mechanism (RRM) is an annual rate filing mechanism that allows us to refresh our rates on a periodic basis without filing a formal rate case. The current RRM program was approved by the Mid-Tex Cities in the summer of 2013. The first filing under the mechanism was made in July of 2013 and has been settled for $12.5 million to be implemented on November 1, 2013.

(5) The Stable Rate Filing shows no deficiency, thus no change in operating income is anticipated from the current year filing.

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Our recent ratemaking activity is discussed in greater detail below.

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 divisions 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, Kansas, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2013, 2012 and 2011:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2013 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2012	$156,440	$26,730	05/07/2013
Colorado-Kansas — Kansas	09/2012	5,376	601	01/09/2013
Kentucky/Mid-States — Georgia[1][2]	09/2011	6,519	1,079	10/01/2012
Kentucky/Mid-States — Kentucky[2]	09/2013	19,296	2,425	10/01/2012
Kentucky/Mid-States — Virginia	09/2013	756	101	10/01/2012
Total 2013 Infrastructure Programs		$188,387	$30,936	
2012 Infrastructure Programs:				
Mid-Tex Unincorporated (Environs)[3]	12/2011	$145,671	$744	06/26/2012
Atmos Pipeline — Texas	12/2011	87,210	14,684	04/10/2012
Kentucky/Mid-States — Georgia[1][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[4]	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States — Georgia[1][2]	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	

(1) On April 1, 2013, we completed the sale of our Georgia operations to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. The increase in operating income arising from the implementation of new rates is included as a component of discontinued operations through March 31, 2013.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure.

(3) 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.

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

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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. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in a portion of our Texas divisions. These mechanisms are referred to as Dallas annual rate review (DARR) and rate review mechanisms (RRM) in our Mid-Tex Division, 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 (In thousands)	Effective Date
2013 Filings:				
Louisiana	LGS	12/31/2012	$908	07/01/2013
Mid-Tex	City of Dallas	9/30/2012	1,800	06/01/2013
Louisiana	TransLa	9/30/2012	2,260	04/01/2013
Kentucky/Mid-States	Georgia[(1)]	9/30/2013	743	02/01/2013
Mississippi	Mississippi	6/30/2012	3,441	11/01/2012
Total 2013 Filings			$9,152	
2012 Filings:				
Louisiana	LGS	12/31/2011	$2,324	07/01/2012
Mid-Tex	Dallas	9/30/2011	1,204	06/01/2012
Louisiana	Trans La	9/30/2011	11	04/01/2012
Kentucky/Mid-States	Georgia[(1)]	9/30/2011	(818)	02/01/2012
Mississippi	Mississippi	6/30/2011	4,323	01/11/2012
Total 2012 Filings			$7,044	
2011 Filings:				
Mid-Tex	Mid-Tex 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	9/30/2010	350	04/01/2011
Mid-Tex	Mid-Tex Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	

(1) On April 1, 2013, we completed the sale of our Georgia operations to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. The increase in operating income arising from the implementation of new rates is included as a component of discontinued operations through March 31, 2013.

From 2008 through fiscal 2011, the Mid-Tex Division had an annual rate review mechanism (RRM) for approximately 80 percent of its customers, which allowed it to update rates annually without the necessity of filing a general rate case. In fiscal 2013, a new RRM was approved for these customers.

Since June 2011, the Mid-Tex Division has operated under a Dallas Annual Rate Review Mechanism (DARR) that provides the ability for it to annually update rates for its City of Dallas customers without the necessity of filing a general rate case. 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 with operations in Texas 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 until the expenses are included in rates, including the recording of interest on the deferred expenses.

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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 (In thousands)	Effective Date
2013 Rate Case Filings:			
Mid-Tex	Texas	$42,601	12/04/2012
Kentucky/Mid-States	Tennessee	7,530	11/08/2012
West Texas	Texas	6,569	10/01/2012
Total 2013 Rate Case Filings		$56,700	
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	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2013, 2012 and 2011:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2013 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$1,322	02/01/2013
Total 2013 Other Rate Activity			$1,322	
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	

(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 and 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

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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. The FERC also has 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, 2013, we had 4,720 employees, consisting of 4,611 employees in our regulated operations and 109 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 2013, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any

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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:

The Company is dependent on continued access to the credit and capital markets to execute our business strategy.

Our long-term debt is currently rated as “investment grade” by Standard & Poor’s Corporation, Moody’s Investors Services, Inc. and Fitch Ratings, Ltd. Similar to most companies, we rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions were to cause a significant limitation on our access to the private and public capital 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 private credit and/or public capital markets and increase our costs of borrowing.

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 an intercompany lending facility between AEH and Atmos Energy to finance its working capital needs, supplemented by two small credit facilities with outside lenders. Our ability to provide this liquidity to AEH for our nonregulated operations is limited by the terms of the lending arrangement with AEH, which is 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 deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

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 regulatory oversight from various state and local regulatory authorities in the eight states that we serve. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party intervenors. In the normal course of business, a regulated entity often needs to place assets in service and establish historical test periods before rate cases that seek to adjust our allowed returns to recover that investment can be filed. Further, the regulatory review process can be lengthy. Because of this process, we 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.” The regulatory process also involves the risk that regulatory authorities may (i) review our purchases of natural gas and adjust the amount of our gas costs that we pass through to our customers or (ii) limit the costs we may have incurred from our cost of service that can be recovered from customers.

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 several 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 continuing to improve economic conditions, including the continued 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.

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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.

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

We are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics and counterparty creditworthiness and interest rate risk. Our regulated operations are generally insulated from commodity price risk through its purchased gas cost mechanisms. With respect to interest rate risk, we have been operating in a relatively low interest-rate environment in recent years compared to historical norms for both short and long-term interest rates. However, increases in interest rates could adversely affect our future financial results.

Although our nonregulated operations represent approximately five percent of our consolidated results, commodity price volatility experienced in this business segment could lead to some volatility in our earnings. 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.

Although we manage our business to maintain no open positions related to our physical storage, there are times when limited net open positions 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. 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. Further, if the local physical markets 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.

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.

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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.

Finally, 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 from competitors who offer lower cost, basic services.

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 in our natural gas distribution business, 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.

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 rules issued by the RRC's Division of Public Safety that require natural gas distribution companies to develop and implement risk-based programs 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.

The costs of providing health care benefits, pension and postretirement health care benefits and related funding requirements may increase substantially.

We provide health care benefits and a cash-balance pension plan and postretirement health care benefits to eligible full-time employees. The costs of providing health care benefits to our employees could significantly increase over time due to rapidly increasing health care inflation, the impact of the Health Care Reform Act of 2010 (HCR) and any future legislative changes related to the provision of health care benefits. Although the HCR is not expected to have a direct material impact when a number of its more significant provisions become effective in 2014, the impact of costs incurred by the insurance industry arising from the implementation of HCR on the Company are difficult to measure at this time.

The costs of providing a cash-balance pension plan and postretirement health care benefits to eligible full-time employees and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement health care plans. Any significant declines in the value of these investments could increase the costs of our

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pension and postretirement health care 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.

The costs to the Company of providing these 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.

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 72,000 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 eight 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, natural gas distribution and pipeline companies are facing increasing federal, state and local oversight of the safety of their operations. Although we believe these costs should be ultimately recoverable through our rates, 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 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. 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 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.

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

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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.

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. Even though we have insurance coverage in place for many of these cyber-related risks, if such an attack or act of terrorism were to occur, our operations and 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, 2013, in our natural gas distribution segment, we owned an aggregate of 67,146 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. Through our regulated transmission and storage segment we owned 5,628 miles of gas transmission and gathering lines as well as 110 miles of gas transmission and gathering lines through our nonregulated segment.

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, 2013:

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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
Total	9,893,590	11,065,200	20,958,790	198,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated Segment				
Kentucky	3,438,900	3,240,000	6,678,900	67,500
Louisiana	438,583	300,973	739,556	56,000
Total	3,877,483	3,540,973	7,418,456	123,500
Total	59,914,299	30,484,198	90,398,497	1,556,600

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

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Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2013:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	4,261,909	108,489
	Kentucky/Mid-States Division	11,081,603	344,706
	Louisiana Division	2,736,539	161,393
	Mid-Tex Division	1,000,000	75,000
	Mississippi Division	3,695,429	162,402
	West Texas Division	3,375,000	106,000
Total		26,150,480	957,990
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		35,851,349	1,276,434

(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 10 to the consolidated financial statements.

ITEM 4. Mine Safety Disclosures.

Not applicable.

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 2013 and 2012 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:

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	Fiscal 2013			Fiscal 2012		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$36.86	$33.20	$0.35	$35.40	$30.97	$0.345
March 31	42.69	35.11	0.35	33.15	30.60	0.345
June 30	44.87	38.59	0.35	35.07	30.91	0.345
September 30	45.19	39.40	0.35	36.94	34.94	0.345
			$1.40			$1.38

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, 2013 was 16,746. 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 2013 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 S&P 500 Stock Index and the cumulative total return of a customized peer company group, the Comparison Company Index. The Comparison Company Index 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, 2008 in our common stock, the S&P 500 Index and in the common stock of the companies in the Comparison Company Index, as well as a reinvestment of dividends paid on such investments throughout the period.

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

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	Cumulative Total Return					
	9/30/2008	9/30/2009	9/30/2010	9/30/2011	9/30/2012	9/30/2013
Atmos Energy Corporation	100.00	111.68	121.63	140.75	161.81	199.54
S&P 500	100.00	93.09	102.55	103.72	135.05	161.17
Peer Group	100.00	98.11	130.03	153.00	184.92	217.15

The Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by our independent executive 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 following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2013.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	7,930	$ 25.96	1,403,439
Total equity compensation plans approved by security holders	7,930	25.96	1,403,439
Equity compensation plans not approved by security holders	—	—	—
Total	7,930	$ 25.96	1,403,439

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 fiscal 2013. At September 30, 2013, 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				
	2013	2012[(1)]	2011[(1)]	2010	2009[(1)]
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$3,886,257	$3,438,483	$4,286,435	$4,661,060	$4,793,248
Gross profit	$1,412,050	$1,323,739	$1,300,820	$1,314,136	$1,297,682
Income from continuing operations	$230,698	$192,196	$189,588	$189,851	$175,026
Net income	$243,194	$216,717	$207,601	$205,839	$190,978
Diluted income per share from continuing operations	$2.50	$2.10	$2.07	$2.03	$1.90
Diluted net income per share	$2.64	$2.37	$2.27	$2.20	$2.07
Cash dividends declared per share	$1.40	$1.38	$1.36	$1.34	$1.32

Financial Condition					
Net property, plant and equipment(2)	$6,030,655	$5,475,604	$5,147,918	$4,793,075	$4,439,103
Total assets	$7,940,401	$7,495,675	$7,282,871	$6,763,791	$6,367,083
Capitalization:					
Shareholders' equity	$2,580,409	$2,359,243	$2,255,421	$2,178,348	$2,176,761
Long-term debt (excluding current maturities)	2,455,671	1,956,305	2,206,117	1,809,551	2,169,400
Total capitalization	$5,036,080	$4,315,548	$4,461,538	$3,987,899	$4,346,161

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(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”, “str
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; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; the impact of adverse economic conditions on our customers; the effects of inflation and changes in the availability and price of natural gas; market risks beyond our control affecting our risk management activities, including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in Texas; increased competition from energy suppliers and alternative forms of energy; adverse weather conditions; the capital-intensive nature of our gas distribution business; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; 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 inherent hazards and risks involved in operating our gas distribution business; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; 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

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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.

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Regulation	Our natural gas distribution and regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the United States. Accordingly, the financial results for these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject. 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. 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. 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.	Decisions of regulatory authorities Issuance of new regulations Assessing the probability of the recoverability of deferred costs
Unbilled Revenue	We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues attributable 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.	Estimates of delivered sales volumes based on actual tariff information and weather information and estimates of customer consumption and/or behavior Estimates of purchased gas costs related to estimated deliveries Estimates of uncollectible amounts billed subject to refund

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 methodology 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	General economic and market conditions Assumed investment returns by asset class Assumed future salary increases Projected timing of future cash disbursements Health care cost experience trends Participant demographic information Actuarial mortality assumptions Impact of legislation

	retirement is estimated based upon our annual review of our participant census information as of the measurement date.	
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 uncollectible receivables, lawsuits, claims made by third parties or the action of various regulatory agencies. We recognize these contingencies in our consolidated financial statements when we determine, based on currently available facts and circumstances it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. 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 10 to our consolidated financial statements.	Currently available facts Management's estimate of future resolution

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 12 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. The recognition of the changes in fair value of these financial instruments 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. Our accounting elections for financial instruments and hedging activities utilized are more fully described in Note 12 to the consolidated financial statements. 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. Finally, changes in the effectiveness of the hedge relationship could impact the accounting treatment.	Designation of contracts under the hedge accounting rules Judgment in the application of accounting guidance Assessment of the probability that future hedged transactions will occur Changes in market conditions and the related impact on the fair value of the hedged item and the associated designated financial instrument Changes in the effectiveness of the hedge relationship
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). The fair value of our financial instruments is subject to potentially significant volatility based on numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and settlement of these financial instruments. 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	General economic and market conditions Volatility in underlying market conditions Maturity dates of financial instruments Creditworthiness of our counterparties Creditworthiness of Atmos Energy Impact of credit risk mitigation activities on the assessment of the creditworthiness of Atmos Energy and its counterparties

reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions.

We believe the market prices and models used to value these financial instruments represent the best information available with respect to the market in which transactions involving these financial instruments are executed, the closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

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.

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 U.S. 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 affect these estimates, which could result in an impairment charge.	General economic and market conditions Projected timing and amount of future discounted cash flows Judgment in the evaluation of relevant data

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. Historically, this has generally resulted 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 54 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. However, we believe rate design changes implemented during the first quarter of fiscal 2013 in our Mid-Tex and West Texas Divisions should continue to cause this pattern to change. The rate design approved in these regulatory proceedings includes an increase to the customer base charge and a decrease in the consumption charge applied to customer usage. The effect of this change in rate design should result in a more equal distribution of operating income earned over the fiscal year for approximately 50 percent of our natural gas distribution segment.

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 2013, we earned $243.2 million, or $2.64 per diluted share, which represents a twelve percent increase in net income and diluted net income per share over fiscal 2012, primarily due to recent improvements in rate designs in our natural gas distribution and regulated transmission and storage segments combined with a two percent year-over-year increase in consolidated natural gas distribution throughput due to colder weather.

We completed the sale of our Georgia natural gas distribution operations on April 1, 2013 to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million pursuant to a purchase agreement executed on August 8, 2012. In connection with the sale, we recognized a net of tax gain of $5.3 million. Accordingly, the results of operations for this service area are shown in discontinued operations for all periods presented. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The sale of these three service areas was completed in August 2012.

We also took several steps during the year ended September 30, 2013 to further strengthen our balance sheet and borrowing capability. In December 2012, we amended our $750 million revolving credit agreement primarily to (i) increase our borrowing capacity to $950 million while retaining the accordion feature that would allow an increase in borrowing capacity up to $1.2 billion and (ii) to permit same-day funding on base rate loans. In August 2013, we amended our revolving credit agreement primarily to increase the term through August 2018. We also terminated Atmos Energy Marketing's $200 million committed and secured credit facility and replaced this facility with two $25 million 364-day bilateral facilities, which should result in a decrease in external credit expense incurred in our nonregulated operations. After giving effect to these changes, we have over $1 billion of working capital funding from four committed revolving credit facilities and one noncommitted revolving credit facility.

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On January 11, 2013, we issued $500 million of 4.15% 30-year unsecured senior notes, which replaced, on a long-term basis, our $250 million 5.125% 10-year unsecured senior notes we redeemed in August 2012. The net proceeds of approximately $494 million were used to repay $260 million outstanding under the short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2013, 2012 and 2011.

	For the Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands, except per share data)		
Operating revenues	$3,886,257	$3,438,483	$4,286,435
Gross profit	1,412,050	1,323,739	1,300,820
Operating expenses	910,171	877,499	874,834
Operating income	501,879	446,240	425,986
Miscellaneous income (expense)	(197)	(14,644)	21,184
Interest charges	128,385	141,174	150,763
Income from continuing operations before income taxes	373,297	290,422	296,407
Income tax expense	142,599	98,226	106,819
Income from continuing operations	230,698	192,196	189,588
Income from discontinued operations, net of tax	7,202	18,172	18,013
Gain on sale of discontinued operations, net of tax	5,294	6,349	—
Net income	$243,194	$216,717	$207,601
Diluted net income per share from continuing operations	$2.50	$2.10	$2.07
Diluted net income per share from discontinued operations	$0.14	$0.27	$0.20
Diluted net income per share	$2.64	$2.37	$2.27

Regulated operations contributed 95 percent, 97 percent and 104 percent to our consolidated net income from continuing operations for fiscal years 2013, 2012 and 2011. 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		
	2013	2012	2011
	(In thousands)		
Natural gas distribution segment	$150,856	$123,848	$144,705
Regulated transmission and storage segment	68,260	63,059	52,415
Nonregulated segment	11,582	5,289	(7,532)
Net income from continuing operations	230,698	192,196	189,588
Net income from discontinued operations	12,496	24,521	18,013
Net income	$243,194	$216,717	$207,601

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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		
	2013	2012	2011
	(In thousands, except per share data)		
Regulated operations	$219,116	$186,907	$197,120
Nonregulated operations	11,582	5,289	(7,532)
Net income from continuing operations	230,698	192,196	189,588
Net income from discontinued operations	12,496	24,521	18,013
Net income	$243,194	$216,717	$207,601
Diluted EPS from continuing regulated operations	$2.38	$2.04	$2.15
Diluted EPS from nonregulated operations	0.12	0.06	(0.08)
Diluted EPS from continuing operations	2.50	2.10	2.07
Diluted EPS from discontinued operations	0.14	0.27	0.20
Consolidated diluted EPS	$2.64	$2.37	$2.27

We reported net income of $243.2 million, or $2.64 per diluted share for the year ended September 30, 2013, compared with net income of $216.7 million or $2.37 per diluted share in the prior year. Income from continuing operations was $230.7 million, or $2.50 per diluted share compared with $192.2 million, or $2.10 per diluted share in the prior-year period. Income from discontinued operations was $12.5 million or $0.14 per diluted share for the year, which includes the gain on sale of substantially all our assets in Georgia of $5.3 million, compared with $24.5 million or $0.27 per diluted share in the prior year. Unrealized gains in our nonregulated operations during the current year increased net income by $5.3 million or $0.05 per diluted share compared with net losses recorded in the prior year of $5.0 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2012, net income included the net positive impact of several one-time items totaling $10.3 million, or $0.11 per diluted share related to the pre-tax items, which are discussed in further detail below. In fiscal 2013, net income includes an $8.2 million ($5.3 million, net of tax), or $0.06 per diluted share, favorable impact related to the gain recorded in association with the April 1, 2013 completion of the sale of our Georgia assets.

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 fiscal 2011. 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 fiscal 2011. 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 fiscal 2011. Unrealized losses in our nonregulated operations during fiscal 2012 reduced net income by $5.0 million or $0.05 per diluted share compared with net losses recorded in fiscal 2011 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 pre-tax items. In fiscal 2012, net income included 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 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.

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

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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 receipt taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenue 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.

Although the cost of gas typically does not have a direct impact on our gross profit, 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.

We completed the sale of our Georgia natural gas distribution operations on April 1, 2013 to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million. In connection with the sale, we recognized a net of tax gain of $5.3 million. On August 1, 2012, we completed the sale of substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa.

During fiscal 2013, we completed 13 regulatory proceedings, which should result in a $71.4 million increase in annual operating income. The majority of this rate increase related to our Mid-Tex Division, where rates became effective January 1, 2013. The rate design approved in our Mid-Tex Division and West Texas Division regulatory proceedings includes an increase to the base customer charge and a decrease in the commodity charge applied to customer consumption. The effect of this change in rate design allows the Company’s rates to be more closely aligned with the utility industry standard rate design. In addition, we anticipate these divisions will earn their operating income more ratably over the fiscal year as they are now less dependent on customer consumption.

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Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Gross profit	$1,081,236	$1,022,743	$1,017,943	$58,493	$4,800
Operating expenses	738,143	718,282	695,855	19,861	22,427
Operating income	343,093	304,461	322,088	38,632	(17,627)
Miscellaneous income (expense)	2,535	(12,657)	16,242	15,192	(28,899)
Interest charges	98,296	110,642	115,740	(12,346)	(5,098)
Income from continuing operations before income taxes	247,332	181,162	222,590	66,170	(41,428)
Income tax expense	96,476	57,314	77,885	39,162	(20,571)
Income from continuing operations	150,856	123,848	144,705	27,008	(20,857)
Income from discontinued operations, net of tax	7,202	18,172	18,013	(10,970)	159
Gain on sale of discontinued operations, net of tax	5,649	6,349	—	(700)	6,349
Net Income	$163,707	$148,369	$162,718	$15,338	$(14,349)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	269,162	244,466	275,540	24,696	(31,074)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	123,144	128,222	125,812	(5,078)	2,410
Consolidated natural gas distribution throughput from continuing operations — MMcf	392,306	372,688	401,352	19,618	(28,664)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	4,731	18,295	22,668	(13,564)	(4,373)
Total consolidated natural gas distribution throughput — MMcf	397,037	390,983	424,020	6,054	(33,037)
Consolidated natural gas distribution average transportation revenue per Mcf	$0.46	$0.43	$0.47	$0.03	$(0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$4.91	$4.64	$5.30	$0.27	$(0.66)

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $58.5 million period-over-period increase in natural gas distribution gross profit primarily reflects the following:

- $25.7 million increase in our Mid-Tex and West Texas divisions associated with the rate design changes implemented in the fiscal first quarter.
- $16.1 million increase in rates in our Kentucky/Mid-States, Mississippi, Colorado-Kansas and Louisiana divisions.
- $7.5 million increase due to colder weather, primarily in the Mississippi, Kentucky/Mid-States and Colorado-Kansas divisions.
- $5.9 million increase in revenue-related taxes in our Mid-Tex and West Texas service areas primarily due to higher revenues on which the tax is calculated.
- $4.5 million increase in transportation revenues.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased by $19.9 million, primarily due to the following:

- $12.2 million increase in employee-related expenses due to lower labor capitalization rates, increased benefit costs and increased variable compensation expense.

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- $11.7 million increase primarily associated with higher line locate activities, pipeline and right-of-way maintenance spending to improve the safety and reliability of our system.
- $5.0 million increase in taxes, other than income due to higher revenue-related taxes, as discussed above.
- $6.8 million increase in bad debt expense primarily attributable to an increase in revenue arising from the rate design changes and the temporary suspension of active customer collection activities following the implementation of a new customer information system during the third fiscal quarter.

These increases were partially offset by:

- $6.9 million decrease in legal and other administrative costs.
- $6.4 million decrease in depreciation expense due to new depreciation rates approved in the most recent Mid-Tex rate case that went into effect in January 2013.
- $2.4 million gain realized on the sale of certain investments.

Miscellaneous income increased $15.2 million, primarily due to the absence of a $10.0 million one-time donation to a donor advised fund in the prior year, the completion of a periodic review of our performance-based ratemaking (PBR) mechanism in our Tennessee service area and the implementation of a new PBR program in our Mississippi Division during fiscal 2013.

Interest charges decreased $12.3 million, primarily from interest deferrals associated with our infrastructure spending activities in Texas.

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 fiscal 2011 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 fiscal 2011.
- $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 fiscal 2011 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 fiscal 2012.

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

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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.

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, 2013, 2012 and 2011. 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				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands)				
Mid-Tex	$158,900	$142,755	$144,204	$16,145	$(1,449)
Kentucky/Mid-States	46,164	32,185	37,593	13,979	(5,408)
Louisiana	52,125	48,958	50,442	3,167	(1,484)
West Texas	28,085	27,875	29,686	210	(1,811)
Mississippi	29,112	27,369	26,338	1,743	1,031
Colorado-Kansas	25,478	23,898	25,920	1,580	(2,022)
Other	3,229	1,421	7,905	1,808	(6,484)
Total	$343,093	$304,461	$322,088	$38,632	$(17,627)

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.

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Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$179,628	$162,808	$125,973	$16,820	$36,835
Third-party transportation	66,939	64,158	73,676	2,781	(9,518)
Storage and park and lend services	5,985	6,764	7,995	(779)	(1,231)
Other	16,348	13,621	11,729	2,727	1,892
Gross profit	268,900	247,351	219,373	21,549	27,978
Operating expenses	129,047	118,527	111,098	10,520	7,429
Operating income	139,853	128,824	108,275	11,029	20,549
Miscellaneous income (expense)	(2,285)	(1,051)	4,715	(1,234)	(5,766)
Interest charges	30,678	29,414	31,432	1,264	(2,018)
Income before income taxes	106,890	98,359	81,558	8,531	16,801
Income tax expense	38,630	35,300	29,143	3,330	6,157
Net income	$68,260	$63,059	$52,415	$5,201	$10,644
Gross pipeline transportation volumes — MMcf	649,740	640,732	620,904	9,008	19,828
Consolidated pipeline transportation volumes — MMcf	467,178	466,527	435,012	651	31,515

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $21.5 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the Gas Reliability Infrastructure Program (GRIP) filings approved by the Railroad Commission of Texas (RRC) during fiscal 2012 and 2013. During fiscal 2012, the RRC approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $14.7 million, effective April 2012. On May 7, 2013, the RRC approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $26.7 million that went into effect with bills rendered on and after May 7, 2013. GRIP filings increased period-over-period gross profit by $19.7 million.

This increase was partially offset by a $10.5 million increase in operating expenses largely attributable to increased depreciation expense as a result of increased capital investments and increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system.

The APT rate case approved by the RRC on April 18, 2011 contained an annual adjustment mechanism, approved for a three-year pilot program, that adjusted regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit. The annual adjustment mechanism expired on June 30, 2013. APT requested to extend the annual adjustment mechanism until November 1, 2017. A hearing to review the request was held on October 29, 2013 with a final decision expected in December 2013.

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 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.

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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 fiscal 2011 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).

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and represent approximately five percent of our consolidated net income.

AEH's primary business is to buy, sell and deliver natural gas at competitive prices to approximately 1,000 customers located primarily in the Midwest and Southeast areas of the United States. AEH accomplishes this objective by aggregating and purchasing gas supply, arranging transportation and storage logistics and effectively managing commodity price risk.

AEH also earns storage and transportation demand fees primarily from our regulated natural gas distribution operations in Louisiana and Kentucky. These demand fees are subject to regulatory oversight and are renewed periodically.

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 buying, selling and delivering natural gas 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.
- Increased or decreased 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. 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.

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Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$39,839	$46,578	$58,990	$(6,739)	$(12,412)
Storage and transportation services	14,641	13,382	14,570	1,259	(1,188)
Other	(103)	3,179	1,841	(3,282)	1,338
Total realized margins	54,377	63,139	75,401	(8,762)	(12,262)
Unrealized margins	8,954	(8,015)	(10,401)	16,969	2,386
Gross profit	63,331	55,124	65,000	8,207	(9,876)
Operating expenses, excluding asset impairment	44,404	36,886	39,113	7,518	(2,227)
Asset impairment	—	5,288	30,270	(5,288)	(24,982)
Operating income (loss)	18,927	12,950	(4,383)	5,977	17,333
Miscellaneous income	2,316	1,035	657	1,281	378
Interest charges	2,168	3,084	4,015	(916)	(931)
Income (loss) from continuing operations before income taxes	19,075	10,901	(7,741)	8,174	18,642
Income tax expense (benefit)	7,493	5,612	(209)	1,881	5,821
Income (loss) from continuing operations	11,582	5,289	(7,532)	6,293	12,821
Loss on sale of discontinued operations, net of tax	(355)	—	—	(355)	—
Net income (loss)	$11,227	$5,289	$(7,532)	$5,938	$12,821
Gross nonregulated delivered gas sales volumes — MMcf	396,561	400,512	446,903	(3,951)	(46,391)
Consolidated nonregulated delivered gas sales volumes — MMcf	343,669	351,628	384,799	(7,959)	(33,171)
Net physical position (Bcf)	12.0	18.8	21.0	(6.8)	(2.2)

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

Gross profit increased $8.2 million for the year ended September 30, 2013 compared to the prior year. Realized margins decreased $8.8 million, primarily attributable to lower gas delivery margins. Consolidated sales volumes decreased two percent due to increased competition which reduced industrial and power generation sales. The impact of lower sales volumes was compounded by a decrease in per-unit margins from 11.6 cents per Mcf to 10.0 cents per Mcf. This decrease was offset by an increase of $17.0 million in unrealized margins, primarily due to the year-over-year timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $7.5 million, primarily due to increased litigation and software support costs, partially offset by reduced employee costs.

Miscellaneous income increased $1.3 million primarily due to a gain realized from the sale of a peaking power facility and related assets during the first quarter of fiscal 2013.

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

Realized margins for gas delivery, storage and transportation services and other services were $63.1 million during the year ended September 30, 2012 compared with $75.4 million for fiscal 2011. The decrease reflects the following:

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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.

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Unrealized margins increased $2.4 million in fiscal 2012 compared to fiscal 2011 primarily due to the year-over-year timing of realized margins on the settlement of hedged natural gas inventory positions.

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 fiscal 2011, 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.

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 (i) have sufficient liquidity for our short-term and long-term needs in a cost-effective manner and (ii) maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

The following table presents our capitalization as of September 30, 2013 and 2012:

	September 30					
	2013			2012		
	(In thousands, except percentages)					
Short-term debt	$367,984	6.8	%	$570,929	11.7	%
Long-term debt	2,455,671	45.4	%	1,956,436	40.0	%
Shareholders’ equity	2,580,409	47.8	%	2,359,243	48.3	%
Total capitalization, including short-term debt	$5,404,064	100.0	%	$4,886,608	100.0	%

Total debt as a percentage of total capitalization, including short-term debt, was 52.2 percent and 51.7 percent at September 30, 2013 and 2012.

On January 11, 2013, we issued $500 million of 4.15% 30-year unsecured senior notes, which, in effect, replaced our $250 million 5.125% 10-year unsecured senior notes we redeemed in August 2012, on a long-term basis. The net proceeds of approximately $494 million were used to repay $260 million outstanding under our short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes.

Going forward, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2013 as we continue to invest in the safety and reliability of our distribution and transportation system. We plan to continue to fund our growth and maintain a balanced capital structure through the use of long-term debt securities and, to a lesser extent, equity.

Further, $500 million of long-term debt will mature in October 2014. We plan to issue new senior notes to replace this maturing debt. During the current year, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with this anticipated issuance at 3.129%. 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 2014.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These factors 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.

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Cash flows from operating, investing and financing activities for the years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$613,127	$586,917	$582,844	$26,210	$4,073
Investing activities	(696,914)	(609,260)	(627,386)	(87,654)	18,126
Financing activities	85,747	(44,837)	44,009	130,584	(88,846)
Change in cash and cash equivalents	1,960	(67,180)	(533)	69,140	(66,647)
Cash and cash equivalents at beginning of period	64,239	131,419	131,952	(67,180)	(533)
Cash and cash equivalents at end of period	$66,199	$64,239	$131,419	$1,960	$(67,180)

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, 2013 compared with fiscal year ended September 30, 2012

For the fiscal year ended September 30, 2013, we generated operating cash flow of $613.1 million from operating activities compared with $586.9 million in the prior year. The year-over-year increase reflects changes in working capital offset by a $10.5 million decrease in contributions made to our pension and postretirement plans in the current year.

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 fiscal 2011. The year-over-year increase reflects changes in working capital offset by a $56.7 million increase in contributions made to our pension and postretirement plans during fiscal 2012.

Cash flows from investing activities

Our ongoing capital expenditure 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 and enhance the integrity of our pipelines. In recent years, we have increased our level of capital spending to improve the safety and reliability of our distribution system and to expand our intrastate pipeline network. Over the last three fiscal years, approximately 68 percent of our capital spending has been committed to improving the safety and reliability of our system.

Over the next five years, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2013 as we continue to invest in the safety and reliability of our distribution and transportation system. Where possible, we will also continue to focus 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.

For the fiscal year ended September 30, 2013, we incurred $845.0 million for capital expenditures compared with $732.9 million for the fiscal year ended September 30, 2012 and $623.0 million for the fiscal year ended September 30, 2011.

Fiscal Year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $112.1 million increase in capital expenditures in fiscal 2013 compared to fiscal 2012 primarily reflects spending incurred for the Line W and Line WX expansion projects and increased cathodic protection spending in our regulated transmission and storage segment.

Fiscal Year ended September 30, 2012 compared with fiscal year ended September 30, 2011

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.

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Cash flows from financing activities

We received a net $85.7 million and $44.0 million in cash from financing activities for fiscal years 2013 and 2011. In fiscal 2012, we used a net $44.8 million in financing activities. Our significant financing activities for the fiscal years ended September 30, 2013, 2012 and 2011 are summarized as follows:

2013

During the fiscal year ended September 30, 2013, our financing activities generated $85.7 million of cash compared with $44.8 million of cash used in the prior year. Current year cash flows from financing activities were significantly influenced by the issuance of $500 million 4.15% 30-year unsecured senior notes on January 11, 2013. We used a portion of the net cash proceeds of $493.8 million to repay a $260 million short-term financing facility executed in fiscal 2012, to settle, for $66.6 million, three Treasury Locks associated with the issuance and to reduce short-term debt borrowings by $167.2 million.

2012

During the fiscal year ended September 30, 2012, our financing activities used $44.8 million of cash, primarily due to the payment of $257.0 million associated with the early redemption of our $250 million 5.125% Senior notes that were scheduled to mature in January 2013. The repayment of our $250 million 5.125% Senior notes was financed using a $260 million short-term loan. Additionally, we repurchased $12.5 million of common stock under our 2011 share repurchase program.

2011

During the fiscal year ended September 30, 2011, our financing activities generated $44.0 million of cash, primarily related to the issuance of $400 million 5.50% Senior Notes in June 2011 and the related settlement of three Treasury locks for $20.1 million. We used a portion of the net cash proceeds of $394.5 million to pay scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date in May 2011. Additionally, we received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.

The following table shows the number of shares issued for the fiscal years ended September 30, 2013, 2012 and 2011:

	For the Fiscal Year Ended September 30		
	2013	2012	2011
Shares issued:			
1998 Long-term incentive plan	531,672	482,289	675,255
Outside directors stock-for-fee plan	2,088	2,375	2,385
Total shares issued	533,760	484,664	677,640

The increase in the number of shares issued in fiscal 2013 compared with the number of shares issued in fiscal 2012 primarily reflects the type of awards that were issued from the 1998 Long-Term Incentive Plan (LTIP). In the current year, employees were issued restricted stock units, for which we issued new shares. In the prior year, employees were issued restricted stock awards, which were held in trust and did not require the issuance of new shares. During fiscal 2013, we canceled and retired 133,449 shares attributable to federal withholdings on equity awards which are not included in the table above. At September 30, 2013, of the 8.7 million shares authorized for issuance from the LTIP, 1.4 million shares remained available.

The decreased number of shares issued in fiscal 2012 compared with the number of shares issued in fiscal 2011 primarily reflects the exercise of a significant number of stock options during fiscal 2011. During fiscal 2012, we canceled 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.

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 $950 million commercial paper program, which is collateralized by our $950 million unsecured credit facility, as well as three additional committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. As a result, we have approximately $1 billion of working capital funding. Additionally, our $950 million unsecured credit facility has an accordion feature, which, if utilized, would increase borrowing capacity to $1.2 billion. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

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On March 28, 2013, we filed a registration statement with the Securities and Exchange Commission to issue, from time to time, up to $1.75 billion in common stock and/or debt securities available for issuance, which replaced our registration statement that expired on March 31, 2013. As of September 30, 2013, $1.75 billion was available under the shelf registration statement.

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	A-	Baa1	A-
Commercial paper	A-2	P-2	F-2

On October 8, 2013, S&P upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing an improved business risk profile from an increasing contribution of earnings from our regulated operations and focusing our nonregulated operations on our delivered gas business.

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, 2013. Our debt covenants are described in Note 5 to the consolidated financial statements.

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Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2013.

	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]	$2,460,000	$—	$500,000	$250,000	$1,710,000
Short-term debt[1]	367,984	367,984	—	—	—
Interest charges[2]	1,918,491	144,317	240,097	218,585	1,315,492
Gas purchase commitments[3]	230,480	230,480	—	—	—
Capital lease obligations[4]	822	186	372	264	—
Operating leases[4]	166,802	16,722	30,276	30,131	89,673
Demand fees for contracted storage[5]	6,088	4,196	1,252	284	356
Demand fees for contracted transportation[6]	13,098	8,466	4,604	28	—
Financial instrument obligations[7]	7,676	1,543	6,133	—	—
Pension and postretirement benefit plan contributions[8]	411,623	67,687	101,176	82,976	159,784
Uncertain tax positions (including interest)[9]	3,172	—	3,172	—	—
Total contractual obligations	$5,586,236	$841,581	$887,082	$582,268	$3,275,305

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

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

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2013.

(4) See Note 9 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, 2013. 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 pension and postretirement benefit plans, which are discussed in Note 6 to the consolidated financial statements.

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

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, 2013 are reflected in the table above.

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, 2013, AEH was committed to purchase 78.0 Bcf within one year, 21.9 Bcf within one to three years and 1.0 Bcf after three years under indexed contracts. AEH is committed to purchase 6.1 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $3.32 to $6.36 per Mcf.

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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 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, 2013 (in thousands):

Fair value of contracts at September 30, 2012	$(76,260)
Contracts realized/settled	2,590
Fair value of new contracts	3,077
Other changes in value	180,241
Fair value of contracts at September 30, 2013	$109,648

The fair value of our natural gas distribution segment's financial instruments at September 30, 2013, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2013				
	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	$294	$109,354	$—	$—	$109,648
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$294	$109,354	$—	$—	$109,648

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, 2013 (in thousands):

Fair value of contracts at September 30, 2012	$(15,123)
Contracts realized/settled	(245)
Fair value of new contracts	—
Other changes in value	668
Fair value of contracts at September 30, 2013	(14,700)
Netting of cash collateral	24,829
Cash collateral and fair value of contracts at September 30, 2013	$10,129

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The fair value of our nonregulated segment's financial instruments at September 30, 2013, is presented below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at September 30, 2013 Maturity in years Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(8,567)	$(5,957)	$(176)	$—	$(14,700)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(8,567)	$(5,957)	$(176)	$—	$(14,700)

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 four 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. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2014, we anticipate an approximate six 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, 2013, our total net periodic pension and other benefits costs was $78.5 million, compared with $69.2 million and $56.6 million for the fiscal years ended September 30, 2012 and 2011. 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 2013 costs were determined using a September 30, 2012 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates 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. Our expected return on our pension plan assets was maintained at 7.75 percent due to historical experience and the current market projection of the target asset allocation. As a result, our fiscal 2013 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 2012 compared with fiscal 2011 primarily reflects the decrease in our discount rate at September 30, 2011, the measurement date for our fiscal 2012 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, 2011 measurement date, the interest and corporate bond rates used to determine our fiscal 2012 net periodic pension cost were significantly lower than the rates at September 30, 2010, the measurement date used to determine our fiscal 2011 net periodic cost. Our expected return on our pension plan assets was reduced to 7.75 percent due to historical experience and the then-current market projection of the target asset allocation.

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

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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, 2013. Based on this valuation, we were required to contribute cash of $32.7 million, $46.5 million and $0.9 million to our pension plans during fiscal 2013, 2012 and 2011. The higher level of contributions experienced during fiscal 2013 and 2012 reflect lower discount rates than in previous years. Each contribution increased the level of our plan assets to achieve a desirable PPA funding threshold.

We contributed $26.6 million and $22.1 million to our postretirement benefits plans for the fiscal years ended September 30, 2013 and 2012. 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 2014 and Beyond

As of September 30, 2013, interest and corporate bond rates were higher than the rates as of September 30, 2012. Therefore, we increased the discount rate used to measure our fiscal 2014 net periodic cost from 4.04 percent to 4.95 percent. However, we decreased the expected return on plan assets from 7.75 percent to 7.25 percent in the determination of our fiscal 2014 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2014 net period pension cost to decrease by less than five percent.

Based upon market conditions subsequent to September 30, 2013, the current funded position of the plans and the funding requirements under the PPA, we anticipate contributing between $15 million and $25 million to the Plans in fiscal 2014. 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 2014.

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 $2.8 million. A 0.25 percent change in our expected
rate of return would impact our pension and postretirement costs by approximately $1.0 million.

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

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

We conduct risk management activities through both our natural gas distribution and 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 12 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

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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, 2013 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, 2013 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 $3.7 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 $3.2 million during 2013.

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ITEM 8. Financial Statements and Supplementary Data.

Index to financial statements and financial statement schedule:

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

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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, 2013 and 2012, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2013. 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, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2013, 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, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated November 13, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
November 13, 2013

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ATMOS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	September 30 2013	2012
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$7,446,272	$6,860,358
Construction in progress	275,747	274,112
	7,722,019	7,134,470
Less accumulated depreciation and amortization	1,691,364	1,658,866
Net property, plant and equipment	6,030,655	5,475,604
Current assets		
Cash and cash equivalents	66,199	64,239
Accounts receivable, less allowance for doubtful accounts of $20,624 in 2013 and $9,425 in 2012	301,992	234,526
Gas stored underground	244,741	256,415
Other current assets	70,334	272,782
Total current assets	683,266	827,962
Goodwill and intangible assets	741,484	740,847
Deferred charges and other assets	484,996	451,262
	$7,940,401	$7,495,675
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2013 — 90,640,211 shares, 2012 — 90,239,900 shares	$453	$451
Additional paid-in capital	1,765,811	1,745,467
Accumulated other comprehensive income (loss)	38,878	(47,607)
Retained earnings	775,267	660,932
Shareholders' equity	2,580,409	2,359,243
Long-term debt	2,455,671	1,956,305
Total capitalization	5,036,080	4,315,548
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	241,611	215,229
Other current liabilities	368,891	489,665
Short-term debt	367,984	570,929
Current maturities of long-term debt	—	131
Total current liabilities	978,486	1,275,954
Deferred income taxes	1,164,053	1,015,083
Regulatory cost of removal obligation	359,299	381,164
Pension and postretirement liabilities	358,787	457,196
Deferred credits and other liabilities	43,696	50,730
	$7,940,401	$7,495,675

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2013	2012	2011
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,399,493	$2,145,330	$2,470,664
Regulated transmission and storage segment	268,900	247,351	219,373
Nonregulated segment	1,598,711	1,351,303	2,024,893
Intersegment eliminations	(380,847)	(305,501)	(428,495)
	3,886,257	3,438,483	4,286,435
Purchased gas cost			
Natural gas distribution segment	1,318,257	1,122,587	1,452,721
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,535,380	1,296,179	1,959,893
Intersegment eliminations	(379,430)	(304,022)	(426,999)
	2,474,207	2,114,744	2,985,615
Gross profit	1,412,050	1,323,739	1,300,820
Operating expenses			
Operation and maintenance	488,020	453,613	442,965
Depreciation and amortization	235,079	237,525	223,832
Taxes, other than income	187,072	181,073	177,767
Asset impairments	—	5,288	30,270
Total operating expenses	910,171	877,499	874,834
Operating income	501,879	446,240	425,986
Miscellaneous income (expense), net	(197)	(14,644)	21,184
Interest charges	128,385	141,174	150,763
Income from continuing operations before income taxes	373,297	290,422	296,407
Income tax expense	142,599	98,226	106,819
Income from continuing operations	230,698	192,196	189,588
Income from discontinued operations, net of tax ($3,986, $10,066 and $12,372)	7,202	18,172	18,013
Gain on sale of discontinued operations, net of tax ($2,909, $3,519 and $0)	5,294	6,349	—
Net income	$243,194	$216,717	$207,601
Basic earnings per share			
Income per share from continuing operations	$2.54	$2.12	$2.08
Income per share from discontinued operations	0.14	0.27	0.20
Net income per share — basic	$2.68	$2.39	$2.28
Diluted earnings per share			
Income per share from continuing operations	$2.50	$2.10	$2.07
Income per share from discontinued operations	0.14	0.27	0.20
Net income per share — diluted	$2.64	$2.37	$2.27
Weighted average shares outstanding:			
Basic	90,533	90,150	90,201
Diluted	91,711	91,172	90,652

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Net income	$243,194	$216,717	$207,601
Other comprehensive income (loss), net of tax			
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(186), $1,881 and $(953)	(213)	3,103	(1,647)
Cash flow hedges:			
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $47,236, $(5,388) and $(16,850)	82,179	(10,116)	(28,689)
Net unrealized gains on commodity cash flow hedges, net of tax of $2,889, $5,029 and $3,355	4,519	7,866	5,248
Total other comprehensive income (loss)	86,485	853	(25,088)
Total comprehensive income	$329,679	$217,570	$182,513

See accompanying notes to condensed consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock					
	Number of Shares	Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2010	90,164,103	$451	$1,714,364	$ (23,372)	$486,905	$2,178,348
Net income	—	—	—	—	207,601	207,601
Other comprehensive loss	—	—	—	(25,088)	—	(25,088)
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
Net income	—	—	—	—	216,717	216,717
Other comprehensive income	—	—	—	853	—	853
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
Net income	—	—	—	—	243,194	243,194
Other comprehensive income	—	—	—	86,485	—	86,485
Repurchase of equity awards	(133,449)	—	(5,150)	—	—	(5,150)
Cash dividends ($1.40 per share)	—	—	—	—	(128,115)	(128,115)
Common stock issued:						
Direct stock purchase plan	—	—	(50)	—	—	(50)
1998 Long-term incentive plan	531,672	2	9,530	—	(744)	8,788
Employee stock-based compensation	—	—	15,934	—	—	15,934
Outside directors stock-for-fee plan	2,088	—	80	—	—	80
Balance, September 30, 2013	90,640,211	$453	$1,765,811	$ 38,878	$775,267	$2,580,409

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2013	2012	2011
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$243,194	$216,717	$207,601
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	—	5,288	30,270
Gain on sale of discontinued operations	(8,203)	(9,868)	—
Depreciation and amortization:			
Charged to depreciation and amortization	236,928	246,093	233,155
Charged to other accounts	679	484	228
Deferred income taxes	141,336	104,319	117,353
Stock-based compensation	17,814	19,222	11,586
Debt financing costs	8,480	8,147	9,438
Other	(2,887)	(493)	(961)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(73,669)	32,578	(96)
Decrease in gas stored underground	31,979	28,417	27,737
(Increase) decrease in other current assets	15,644	20,989	(38,048)
(Increase) decrease in deferred charges and other assets	111,069	(50,055)	(53,519)
Increase (decrease) in accounts payable and accrued liabilities	31,912	(64,234)	23,904
Increase (decrease) in other current liabilities	(44,491)	7,889	(57,495)
Increase (decrease) in deferred credits and other liabilities	(96,658)	21,424	71,691
Net cash provided by operating activities	613,127	586,917	582,844
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(845,033)	(732,858)	(622,965)
Proceeds from the sale of discontinued operations	153,023	128,223	—
Other, net	(4,904)	(4,625)	(4,421)
Net cash used in investing activities	(696,914)	(609,260)	(627,386)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	(208,070)	354,141	83,306
Net proceeds from issuance of long-term debt	493,793	—	394,466
Settlement of Treasury lock agreements	(66,626)	—	20,079
Unwinding of Treasury lock agreements	—	—	27,803
Repayment of long-term debt	(131)	(257,034)	(360,131)
Cash dividends paid	(128,115)	(125,796)	(124,011)
Repurchase of common stock	—	(12,535)	—
Repurchase of equity awards	(5,150)	(5,219)	(5,299)
Issuance of common stock	46	1,606	7,796
Net cash provided by (used in) financing activities	85,747	(44,837)	44,009
Net increase (decrease) in cash and cash equivalents	1,960	(67,180)	(533)
Cash and cash equivalents at beginning of year	64,239	131,419	131,952
Cash and cash equivalents at end of year	$66,199	$64,239	$131,419
CASH PAID (RECEIVED) DURING THE PERIOD FOR:			
Interest	$148,461	$150,606	$157,976
Income taxes	$10,008	$(432)	$(8,329)

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to 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	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 location 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.

Over the last two fiscal years, we have sold our natural gas distribution operations in four states to streamline our regulated operations. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers, and in August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers.

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.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is a wholly-owned subsidiary of 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 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

to regulatory decisions in their financial statements. 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. 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.

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, 2013 and 2012 included the following:

	September 30	
	2013	2012
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$187,977	$296,160
Merger and integration costs, net	5,250	5,754
Deferred gas costs	15,152	31,359
Regulatory cost of removal asset	10,008	10,500
Rate case costs	6,329	4,661
Deferred franchise fees	—	2,714
Texas Rule 8.209[2]	30,364	5,370
APT annual adjustment mechanism	5,853	4,539
Recoverable loss on reacquired debt	21,435	23,944
Other	4,380	7,262
	$286,748	$392,263
Regulatory liabilities:		
Deferred gas costs	$16,481	$23,072
Deferred franchise fees	1,689	—
Regulatory cost of removal obligation	427,524	459,688
Other	7,887	5,637
	$453,581	$488,397

(1) Includes $17.4 million and $7.6 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Texas Rule 8.209 is a Railroad Commission rule that 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.

The amounts above do not include regulatory assets and liabilities related to our Georgia operations, which were classified as assets held for sale at September 30, 2012 as discussed in Note 16. As of September 30, 2013, we did not have any assets or liabilities classified as held for sale due to the sale of substantially all of our Georgia assets on April 1, 2013.

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, 2013, 2012 and 2011, we recognized $0.5 million, $0.5 million and $0.5 million in amortization expense related to these costs.

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

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by 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 distribution companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of their 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 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 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, 2013, 2012 and 2011, we included unrealized gains (losses) on open contracts of $9.0 million, $(8.0) million and $(10.4) million as a component of nonregulated revenues.

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. We establish an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect based on our collection experience or where we are aware of a specific customer's inability or reluctance to pay. 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 $1.9 million, $2.6 million and $1.7 million was capitalized in 2013, 2012 and 2011.

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 3.3 percent, 3.6 percent and 3.6 percent for the fiscal years ended September 30, 2013, 2012 and 2011.

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, 2013 and 2012, we had asset retirement obligations of $6.8 million and $10.5 million. Additionally, we had $3.3 million and $5.8 million of asset retirement costs recorded 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 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 14 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, 2013 and 2012, 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 12.

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. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

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, 2013 and 2012, the Company netted $24.8 million and $23.7 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 and forward starting interest rate swaps to mitigate interest rate risk. Unrealized gains and losses associated with the swaps are recorded as a component of accumulated other comprehensive income (loss). When the 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.

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, including, but not limited to, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions and interest rates, 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. 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.

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. We utilize models and other valuation methods to determine fair value when external sources are not available. 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.

As of September 30, 2013 our Master Trust owned one real estate investment with a value less than $0.2 million that qualifies as a Level 3 fair value measurement. The valuation technique used was a real estate appraisal obtained from an independent third party that consisted of several unobservable inputs such as comparable land and building sales values per square foot. 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.

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 determined 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.

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 — Except as disclosed in Note 6 concerning the October 2, 2013 payment from our Supplemental Executive Benefits Plan related to the retirement of one of our executives, 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, 2013, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard clarifies the enhanced disclosure of offsetting arrangements for financial instruments that will become effective for us for annual and interim periods beginning on October 1, 2013. The adoption of this standard should not have an impact on our financial position, results of operations or cash flows. The second standard changes the presentation requirements for an unrecognized tax benefit if a net operating loss carryforward or tax credit carryforward exists, which will become effective for us for annual and interim periods beginning on October 1, 2014. The adoption of this standard should not have a material impact on our financial position, results of operations or cash flows.

Beginning in our first fiscal quarter, we have presented a single statement of other comprehensive income, due to an accounting pronouncement that became effective for us on October 1, 2012. Additionally, a standard that became effective during our second fiscal quarter requires the presentation of amounts reclassified out of accumulated other comprehensive income by component as well as significant amounts reclassified out of accumulated other comprehensive income by the respective line item in the statement of net income. We have presented the disclosures relating to reclassifications out of accumulated other comprehensive income in Note 13. The adoption of these standards did 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, 2013.

3. Segment Information

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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 eight states. In addition, we transport natural gas for others through our distribution system.

Through our nonregulated business, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and 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.

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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, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,394,418	$89,011	$1,402,828	$—	$3,886,257
Intersegment revenues	5,075	179,889	195,883	(380,847)	—
	2,399,493	268,900	1,598,711	(380,847)	3,886,257
Purchased gas cost	1,318,257	—	1,535,380	(379,430)	2,474,207
Gross profit	1,081,236	268,900	63,331	(1,417)	1,412,050
Operating expenses					
Operation and maintenance	375,188	76,686	37,569	(1,423)	488,020
Depreciation and amortization	195,581	35,302	4,196	—	235,079
Taxes, other than income	167,374	17,059	2,639	—	187,072
Total operating expenses	738,143	129,047	44,404	(1,423)	910,171
Operating income	343,093	139,853	18,927	6	501,879
Miscellaneous income (expense)	2,535	(2,285)	2,316	(2,763)	(197)
Interest charges	98,296	30,678	2,168	(2,757)	128,385
Income from continuing operations before income taxes	247,332	106,890	19,075	—	373,297
Income tax expense	96,476	38,630	7,493	—	142,599
Income from continuing operations	150,856	68,260	11,582	—	230,698
Income from discontinued operations, net of tax	7,202	—	—	—	7,202
Gain (loss) on sale of discontinued operations, net of tax	5,649	—	(355)	—	5,294
Net income	$163,707	$68,260	$11,227	$—	$243,194
Capital expenditures	$528,599	$313,230	$3,204	$—	$845,033

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ATMOS ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	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

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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

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

	2013	2012	2011
	(In thousands)		
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,512,495	$1,351,479	$1,535,887
Commercial	661,930	587,651	685,380
Industrial	81,155	71,960	96,636
Public authority and other	60,557	54,334	68,676
Total gas sales revenues	2,316,137	2,065,424	2,386,579
Transportation revenues	55,938	53,924	57,331
Other gas revenues	22,343	25,028	25,871
Total natural gas distribution revenues	2,394,418	2,144,376	2,469,781
Regulated transmission and storage revenues	89,011	92,604	87,141
Nonregulated revenues	1,402,828	1,201,503	1,729,513
Total operating revenues	$3,886,257	$3,438,483	$4,286,435

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ATMOS ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at September 30, 2013 and 2012 by segment is presented in the following tables.

	September 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,719,873	$1,249,767	$61,015	$—	$6,030,655
Investment in subsidiaries	831,136	—	(2,096)	(829,040)	—
Current assets					
Cash and cash equivalents	4,237	—	61,962	—	66,199
Assets from risk management activities	1,837	—	16,262	—	18,099
Other current assets	428,366	11,709	452,126	(293,233)	598,968
Intercompany receivables	783,738	—	—	(783,738)	—
Total current assets	1,218,178	11,709	530,350	(1,076,971)	683,266
Intangible assets	—	—	121	—	121
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	109,354	—	—	—	109,354
Deferred charges and other assets	347,687	19,227	8,728	—	375,642
	$7,800,418	$1,413,165	$632,829	$(1,906,011)	$7,940,401
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,580,409	$396,421	$434,715	$(831,136)	$2,580,409
Long-term debt	2,455,671	—	—	—	2,455,671
Total capitalization	5,036,080	396,421	434,715	(831,136)	5,036,080
Current liabilities					
Current maturities of long-term debt	—	—	—	—	—
Short-term debt	645,984	—	—	(278,000)	367,984
Liabilities from risk management activities	1,543	—	—	—	1,543
Other current liabilities	491,681	20,288	110,306	(13,316)	608,959
Intercompany payables	—	712,768	70,970	(783,738)	—
Total current liabilities	1,139,208	733,056	181,276	(1,075,054)	978,486
Deferred income taxes	871,360	283,554	8,960	179	1,164,053
Noncurrent liabilities from risk management activities	—	—	6,133	—	6,133
Regulatory cost of removal obligation	359,299	—	—	—	359,299
Pension and postretirement liabilities	358,787	—	—	—	358,787
Deferred credits and other liabilities	35,684	134	1,745	—	37,563
	$7,800,418	$1,413,165	$632,829	$(1,906,011)	$7,940,401

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ATMOS ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	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
Pension and postretirement liabilities	457,196	—	—	—	457,196
Deferred credits and other liabilities	38,334	2,142	1,048	—	41,524
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675

4. 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 units, granted under the 1998 Long-Term Incentive Plan, 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:

	2013	2012	2011
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$230,698	$192,196	$189,588
Less: Income from continuing operations allocated to participating securities	775	793	1,980
Income from continuing operations available to common shareholders	$229,923	$191,403	$187,608
Basic weighted average shares outstanding	90,533	90,150	90,201
Income from continuing operations per share — Basic	$2.54	$2.12	$2.08
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$12,496	$24,521	$18,013
Less: Income from discontinued operations allocated to participating securities	42	101	188
Income from discontinued operations available to common shareholders	$12,454	$24,420	$17,825
Basic weighted average shares outstanding	90,533	90,150	90,201
Income from discontinued operations per share — Basic	$0.14	$0.27	$0.20
Net income per share — Basic	$2.68	$2.39	$2.28
Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$229,923	$191,403	$187,608
Effect of dilutive stock options and other shares	5	4	4
Income from continuing operations available to common shareholders	$229,928	$191,407	$187,612
Basic weighted average shares outstanding	90,533	90,150	90,201
Additional dilutive stock options and other shares	1,178	1,022	451
Diluted weighted average shares outstanding	91,711	91,172	90,652
Income from continuing operations per share — Diluted	$2.50	$2.10	$2.07
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$12,454	$24,420	$17,825
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$12,454	$24,420	$17,825
Basic weighted average shares outstanding	90,533	90,150	90,201
Additional dilutive stock options and other shares	1,178	1,022	451
Diluted weighted average shares outstanding	91,711	91,172	90,652
Income from discontinued operations per share — Diluted	$0.14	$0.27	$0.20
Net income per share — Diluted	$2.64	$2.37	$2.27

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2013, 2012 and 2011.

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ATMOS ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

5. Debt

Long-term debt

Long-term debt at September 30, 2013 and 2012 consisted of the following:

	2013	2012
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 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
Unsecured 4.15% Senior Notes, due 2043	500,000	—
Medium term Series A notes, 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
Total long-term debt	2,460,000	1,960,131
Less:		
Original issue discount on unsecured senior notes and debentures	4,329	3,695
Current maturities	—	131
	$2,455,671	$1,956,305

We issued $500 million Unsecured 4.15% Senior Notes on January 11, 2013. The effective rate of these notes is 4.67%, after giving effect to offering costs and the settlement of the associated Treasury lock agreements discussed in Note 12. Of the net proceeds of approximately $494 million, $234 million was used to partially repay our commercial paper borrowings and for general corporate purposes. The remaining $260 million was used to repay a short-term financing facility that was scheduled to mature on February 1, 2013. This facility was executed on September 27, 2012, with interest rates at a LIBOR based rate plus a company specific spread, to repay commercial paper borrowings that were used to redeem our $250 million Unsecured 5.125% Senior Notes were scheduled to mature 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 borrowings typically reach their highest levels in the winter months.

We currently finance our short-term borrowing requirements through a combination of a $950 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility, with a total availability from third-party lenders of approximately $1 billion of working capital funding. At September 30, 2013 and 2012, there was $368.0 million and $310.9 million outstanding under our commercial paper program with weighted average interest rates of 0.25% and 0.48%, with average maturities of less than one month. 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 $985 million of working capital funding. The first facility is a five-year unsecured facility that was amended on December 7, 2012 to increase the borrowing capacity from $750 million to $950 million with an accordion feature, which, if utilized would increase the borrowing capacity to $1.2 billion. On August 22, 2013 the terms of the facility were amended to extend the expiration date from May 2016 to August 2018. The credit facility 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. At September 30, 2013, there were no borrowings under this facility, but we had $368.0 million of commercial paper outstanding leaving $582.0 million available.

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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. This facility was renewed on April 1, 2013. At September 30, 2013, there were no borrowings outstanding under this facility.

The third facility which was renewed on September 30, 2013 for $10 million is a committed revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate plus 1.5 percent. At September 30, 2013, 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, 2013, 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, 2013, 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 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, 2013. There was $278.0 million outstanding under this facility at September 30, 2013.

Nonregulated Operations

Prior to December 5, 2012, Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, had a three-year $200 million committed revolving credit facility, expiring in December 2014, with a syndicate of third-party lenders with an accordion feature that could increase AEM’s borrowing capacity to $500 million. The credit facility was primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility was collateralized by substantially all of the assets of AEM and was guaranteed by AEH. AEM terminated the committed revolving credit facility on December 5, 2012, to reduce external credit expense. AEM incurred no penalties in connection with the termination. This facility was replaced with two $25 million, 364-day bilateral credit facilities, one of which is a committed facility. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $37.4 million at September 30, 2013.

AEH has a $500 million intercompany demand credit facility with AEC. This facility 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 borrowings under its committed line of credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2013. There were no borrowings outstanding under this facility at September 30, 2013.

Shelf Registration

On March 28, 2013, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $1.75 billion in common stock and/or debt securities available for issuance, which replaced our registration statement that expired on March 31, 2013. As of September 30, 2013, $1.75 billion was available under the shelf registration statement.

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.

We were in compliance with all of our debt covenants as of September 30, 2013. 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.

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Maturities of long-term debt at September 30, 2013 were as follows (in thousands):

2014	$—
2015	500,000
2016	—
2017	250,000
2018	—
Thereafter	1,710,000
	$2,460,000

6. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover most 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.

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, 2013				
Unrecognized transition obligation	$—	$ —	$628	$628
Unrecognized prior service credit	(91)	—	(5,961)	(6,052)
Unrecognized actuarial loss	108,621	31,466	35,961	176,048
	$108,530	$ 31,466	$30,628	$170,624
September 30, 2012				
Unrecognized transition obligation	$—	$ —	$1,709	$1,709
Unrecognized prior service credit	(232)	—	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$186,818	$ 43,995	$57,700	$288,513

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2013, 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 most of the 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.

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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 2013 and 2012 we contributed $32.7 million and $46.5 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. Based upon market conditions subsequent to September 30, 2013, the current funded position of the Plans and the new funding requirements under the PPA, we anticipate contributing between $15 million and $25 million to the Plans in fiscal 2014. 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, 2013 and 2012.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2013		2012	
Domestic equities	35%-55%	46.5	%	42.6	%
International equities	10%-20%	16.1	%	13.9	%
Fixed income	10%-30%	14.9	%	18.6	%
Company stock	5%-15%	12.6	%	12.0	%
Other assets	5%-15%	9.9	%	12.9	%

At September 30, 2013 and 2012, the Plan held 1,169,700 shares of our common stock, which represented 12.6 percent and 12.0 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 2013 and 2012.

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ATMOS ENERGY CORPORATION
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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, 2013 and 2012 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2012, 2011 and 2010. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2013	2012	2013	2012	2011
Discount rate	4.95%	4.04%	4.04%	5.05%	5.39% (1)
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	4.00%
Expected return on plan assets	7.25%	7.75%	7.75%	7.75%	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, 2013 and 2012:

	2013	2012
	(In thousands)	
Accumulated benefit obligation	$446,133	$468,440
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$480,031	$429,432
Service cost	17,754	15,084
Interest cost	19,334	21,568
Actuarial (gain) loss	(29,822)	46,197
Benefits paid	(25,073)	(24,553)
Divestitures	(6,425)	(7,697)
Benefit obligation at end of year	455,799	480,031
Change in plan assets:		
Fair value of plan assets at beginning of year	343,144	280,204
Actual return on plan assets	52,496	48,656
Employer contributions	32,745	46,534
Benefits paid	(25,073)	(24,553)
Divestitures	(6,425)	(7,697)
Fair value of plan assets at end of year	396,887	343,144
Reconciliation:		
Funded status	(58,912)	(136,887)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(58,912)	$(136,887)

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net periodic pension cost for the Plans for fiscal 2013, 2012 and 2011 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$17,754	$15,084	$14,384
Interest cost	19,334	21,568	22,264
Expected return on assets	(22,955)	(21,474)	(24,817)
Amortization of prior service credit	(141)	(141)	(429)
Recognized actuarial loss	19,066	14,451	9,498
Curtailment gain	—	—	(40)
Net periodic pension cost	$33,058	$29,488	$20,860

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2013 and 2012. 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 were 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 $0.4 million and $0.5 million at September 30, 2013 and 2012 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks — domestic equities	$143,543	$—	$—	$143,543
Money market funds	—	12,266	—	12,266
Registered investment companies:				
Domestic funds	30,200	—	—	30,200
International funds	47,036	—	—	47,036
Common/collective trusts — domestic funds	—	57,627	—	57,627
Government securities:				
Mortgage-backed securities	—	18,446	—	18,446
U.S. treasuries	4,117	663	—	4,780
Corporate bonds	—	35,012	—	35,012
Limited partnerships	—	47,417	—	47,417
Real estate	—	—	155	155
Total investments at fair value	$224,896	$171,431	$155	$396,482

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	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

The fair value of our Level 3 real estate assets was determined using a real estate appraisal obtained from an independent third party that consisted of several unobservable inputs such as comparable land sales values per square foot in the range of $0.94 to $2.98 and comparable building sales values per square foot in the range of $23.13 to $30.42.

Supplemental Executive Retirement Plans

We have three nonqualified supplemental plans which provide additional pension, disability and death benefits to our officers, division presidents and certain other employees of the Company.

The first plan is referred to as the Supplemental Executive Benefits Plan (SEBP) and covers our officers, division presidents and certain other employees of the Company who were employed on or before August 12, 1998. The SEBP is a defined benefit arrangement which provides a benefit equal to 75 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SEBP.

In August 1998, we adopted the Supplemental Executive Retirement Plan (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all officers or division presidents selected to participate in the plan between August 12, 1998 and August 5, 2009, any corporate officer who may be appointed to the Management Committee after August 5, 2009 and any other employees selected by our Board of Directors at its discretion. 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.

Effective August 5, 2009, we adopted a new defined benefit Supplemental Executive Retirement Plan (the 2009 SERP), for corporate officers (other than such officer who is appointed as a member of the Company's Management Committee), division presidents or any other employees selected at 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%).

On April 1, 2013, due to the retirement of certain executives, we recognized a settlement loss of $3.2 million associated with the supplemental plans and revalued the net periodic pension cost for the remainder of fiscal 2013. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective April 1, 2013, to 4.21 percent, which reduced our net periodic pension cost by approximately $0.1 million for the remainder of the fiscal year.

On October 2, 2013, due to the retirement of one of our executives, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan. In association with the retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental 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, 2013 and 2012 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2012, 2011 and 2010. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2013	2012	2013	2012	2011
Discount rate	4.95 %	4.04 %	4.04 %[1]	5.05 %	5.39 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	3.50 %	4.00 %

(1) The discount rate for the supplemental plans increased from 4.04% to 4.21% effective April 1, 2013 due to a settlement loss recorded in fiscal 2013.

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2013 and 2012:

	2013	2012
	(In thousands)	
Accumulated benefit obligation	$109,817	$121,815
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$130,186	$112,115
Service cost	3,039	2,108
Interest cost	4,755	5,142
Actuarial (gain) loss	(6,451)	15,459
Benefits paid	(4,375)	(4,638)
Settlements	(10,074)	—
Benefit obligation at end of year	117,080	130,186
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	14,449	4,638
Benefits paid	(4,375)	(4,638)
Settlements	(10,074)	—
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(117,080)	(130,186)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(117,080)	$(130,186)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2013 and 2012, assets held in the rabbi trusts consisted of available-for-sale securities of $44.5 million and $41.8 million, which are included in our fair value disclosures in Note 14.

Net periodic pension cost for the supplemental plans for fiscal 2013, 2012 and 2011 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$3,039	$2,108	$2,768
Interest cost	4,755	5,142	5,825
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	—	—
Recognized actuarial loss	2,918	2,118	2,239
Settlements	3,160	—	—
Net periodic pension cost	$13,872	$9,368	$10,832

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)	
2014	$40,640	$22,940
2015	36,230	6,363
2016	34,752	6,226
2017	33,612	6,440
2018	33,273	6,913
2019-2023	156,367	34,260

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 costs.

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 between $25 million and $30 million to our postretirement benefits plan during fiscal 2014.

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, 2013 and 2012.

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Security Class	Actual Allocation September 30 2013	2012
Diversified investment funds	96.8 %	97.0 %
Cash and cash equivalents	3.2 %	3.0 %

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, 2013 and 2012 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2012, 2011 and 2010. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2013	2012	2013	2012	2011
Discount rate	4.95 %	4.04 %	4.04 %	5.05 %	5.39 %
Expected return on plan assets	4.60 %	4.70 %	4.70 %	5.00 %	5.00 %
Initial trend rate	8.00 %	8.00 %	8.00 %	8.00 %	8.00 %
Ultimate trend rate	5.00 %	5.00 %	5.00 %	5.00 %	5.00 %
Ultimate trend reached in	2020	2019	2019	2018	2016

The following table presents the postretirement plan’s benefit obligation and funded status as of September 30, 2013 and 2012:

	2013	2012
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$308,315	$263,694
Service cost	18,800	16,353
Interest cost	12,964	13,861
Plan participants’ contributions	3,815	3,649
Actuarial (gain) loss	(13,801)	28,815
Benefits paid	(14,458)	(13,197)
Divestitures	(3,487)	(4,860)
Benefit obligation at end of year	312,148	308,315
Change in plan assets:		
Fair value of plan assets at beginning of year	77,072	53,065
Actual return on plan assets	13,432	12,912
Employer contributions	26,552	22,139
Plan participants’ contributions	3,815	3,649
Benefits paid	(14,458)	(13,197)
Divestitures	—	(1,496)
Fair value of plan assets at end of year	106,413	77,072
Reconciliation:		
Funded status	(205,735)	(231,243)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—

Unrecognized net loss	—	—
Accrued postretirement cost	$(205,735)	$(231,243)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net periodic postretirement cost for fiscal 2013, 2012 and 2011 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Components of net periodic postretirement cost:			
Service cost	$18,800	$16,353	$14,403
Interest cost	12,964	13,861	12,813
Expected return on assets	(3,988)	(2,607)	(2,727)
Amortization of transition obligation	1,081	1,511	1,511
Amortization of prior service credit	(1,450)	(1,450)	(1,450)
Recognized actuarial loss	4,196	2,648	347
Net periodic postretirement cost	$31,603	$30,316	$24,897

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	$4,399	$(3,682)
Effect on postretirement benefit obligation	$36,680	$(30,940)

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, 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, 2013 and 2012. 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 were 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, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Money market funds	$—	$3,356	$—	$3,356
Registered investment companies:				
Domestic funds	9,614	—	—	9,614
International funds	93,443	—	—	93,443
Total investments at fair value	$103,057	$3,356	$—	$106,413

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	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

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)			
2014	$25,547	$3,899	$—	$29,446
2015	16,628	4,915	—	21,543
2016	19,260	6,049	—	25,309
2017	21,216	7,304	—	28,520
2018	22,550	8,677	—	31,227
2019-2023	116,617	58,595	—	175,212

Defined Contribution Plans

As of September 30, 2013, 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 become participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction 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 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 $10.4 million, $10.5 million, and $10.2 million for fiscal years 2013, 2012 and 2011. 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 2013, 2012 or 2011. At September 30, 2013 and 2012, the Retirement Savings Plan held 4.9 percent and 4.9 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 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 $1.1 million, $1.2 million and $1.3 million for fiscal years 2013, 2012 and 2011.

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. 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 5-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, 2013, 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 $17.8 million, $19.2 million and $11.6 million for the fiscal years ended September 30, 2013, 2012 and 2011, 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, 2013, 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, 2013, 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 1,403,439 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. We had 7,930 stock options outstanding at September 30, 2013 at a $25.96 weighted average exercise price that are currently vested and expire in November 2014.

Restricted Stock Grants

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 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 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, 2013, 2012 and 2011:

	2013		2012		2011	
	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	1,262,582	$32.46	1,264,142	$29.56	1,293,960	$27.28
Granted	473,775	40.48	532,711	33.44	491,345	33.10
Vested	(657,795)	32.20	(494,308)	26.32	(464,321)	27.21
Forfeited	(25,718)	33.42	(39,963)	29.83	(56,842)	27.56
Nonvested at end of year	1,052,844	$36.20	1,262,582	$32.46	1,264,142	$29.56

As of September 30, 2013, there was $5.1 million of total unrecognized compensation cost related to nonvested time-lapse 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, 2013, 2012 and 2011 was $21.2 million, $13.0 million and $12.6 million.

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 have an annual incentive program covering substantially all 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 with minimum and maximum thresholds. The Company 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.

8. 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, 2013 and 2012:

	September 30	
	2013	2012
	(In thousands)	
Billed accounts receivable	$230,712	$177,953
Unbilled revenue	58,710	42,694
Other accounts receivable	33,194	23,304
Total accounts receivable	322,616	243,951
Less: allowance for doubtful accounts	(20,624)	(9,425)
Net accounts receivable	$301,992	$234,526

Other current assets

Other current assets as of September 30, 2013 and 2012 were comprised of the following accounts.

	September 30	
	2013	2012
	(In thousands)	
Assets from risk management activities	$18,099	$24,707
Deferred gas costs	15,152	31,359
Taxes receivable	3,141	1,291
Current deferred tax asset	—	27,091
Prepaid expenses	21,666	17,114
Materials and supplies	5,511	5,872
Assets held for sale[1]	—	154,571
Other	6,765	10,777
Total	$70,334	$272,782

[1]As discussed in Note 16, assets and liabilities related to our Georgia operations were classified as “assets held for sale” in other current assets and liabilities in our consolidated balance sheets at September 30, 2012.

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Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2013 and 2012:

	September 30	
	2013	2012
	(In thousands)	
Production plant	$5,020	$5,020
Storage plant	262,246	232,260
Transmission plant	1,362,662	1,185,007
Distribution plant	5,061,711	4,680,877
General plant	716,189	717,568
Intangible plant	38,444	39,626
	7,446,272	6,860,358
Construction in progress	275,747	274,112
	7,722,019	7,134,470
Less: accumulated depreciation and amortization	(1,691,364)	(1,658,866)
Net property, plant and equipment[1]	$6,030,655	$5,475,604

(1) Net property, plant and equipment includes plant acquisition adjustments of ($83.8) million and ($91.5) million at September 30, 2013 and 2012.

Goodwill

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2013:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
	(In thousands)			
Balance as of September 30, 2012	$573,550	$132,422	$34,711	$740,683
Deferred tax adjustments on prior acquisitions[1]	640	40	—	680
Balance as of September 30, 2013	$574,190	$132,462	$34,711	$741,363

(1) During the preparation of the fiscal 2013 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.

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2013 and 2012 were comprised of the following accounts.

	September 30	
	2013	2012
	(In thousands)	
Marketable securities	$72,682	$64,398
Regulatory assets	273,287	358,495
Deferred financing costs	15,199	11,157
Assets from risk management activities	109,354	2,283
Other	14,474	14,929
Total	$484,996	$451,262

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Accounts payable and accrued liabilities

Accounts payable and accrued liabilities as of September 30, 2013 and 2012 were comprised of the following accounts.

	September 30	
	2013	2012
	(In thousands)	
Trade accounts payable	$70,116	$82,531
Accrued gas payable	121,202	81,658
Accrued liabilities	50,293	51,040
Total	$241,611	$215,229

Other current liabilities
Other current liabilities as of September 30, 2013 and 2012 were comprised of the following accounts.

	September 30	
	2013	2012
	(In thousands)	
Customer credit balances and deposits	$76,313	$100,926
Accrued employee costs	54,034	37,675
Deferred gas costs	16,481	23,072
Accrued interest	36,744	34,451
Liabilities from risk management activities	1,543	85,381
Taxes payable	66,960	64,319
Pension and postretirement obligations	22,940	39,625
Current deferred tax liability	14,697	—
Regulatory cost of removal accrual	68,225	78,525
Liabilities held for sale	—	11,573
Other	10,954	14,118
Total	$368,891	$489,665

Deferred credits and other liabilities
Deferred credits and other liabilities as of September 30, 2013 and 2012 were comprised of the following accounts.

	September 30	
	2013	2012
	(In thousands)	
Customer advances for construction	$11,723	$12,937
Regulatory liabilities	1,123	5,638
Asset retirement obligation	6,764	10,394
Liabilities from risk management activities	6,133	9,206
Other	17,953	12,555
Total	$43,696	$50,730

9. 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 million at September 30, 2013 and 2012. Accumulated depreciation for these capital leases totaled $1.0 million and $0.9 million at

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September 30, 2013 and 2012. 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, 2013 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2014	$186	$16,722
2015	186	15,584
2016	186	14,692
2017	186	15,074
2018	78	15,057
Thereafter	—	89,673
Total minimum lease payments	822	$166,802
Less amount representing interest	198	
Present value of net minimum lease payments	$624	

Consolidated lease and rental expense amounted to $32.4 million, $33.6 million and $35.5 million for fiscal 2013, 2012 and 2011.

10. 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.

In an opinion handed down on January 25, 2013, the Court of Appeals overturned the $28.5 million jury verdict returned against the Atmos Entities. In a unanimous decision by a three-judge panel, the Court of Appeals reversed the claims asserted by the landowners and investors/working interest owners. The Court of Appeals concluded that all of such claims that the Atmos Entities appealed should have been dismissed by the trial court as a matter of law. The

Court of Appeals let stand the jury verdict on one claim that Atmos Energy and our subsidiaries chose not to appeal, which was a trespass claim. The jury had awarded a total of $10,000 in compensatory damages to one landowner on that claim. The Court of Appeals vacated all of the other damages awarded by the jury and remanded the case to the trial court for a new trial, solely on the issue of whether punitive damages should be awarded to that landowner and, if so, in what amount.

The investors/working interest owners, on February 25, 2013, and the landowners, on March 19, 2013, each filed with the Supreme Court of Kentucky, separate motions for discretionary review of the opinion of the Court of Appeals. We filed a response to the motion filed by the investors/working owners on March 27, 2013 and to the landowners' motion on April 17, 2013. The decision of the Court of Appeals will not become final until the appellate process is completed. We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter and we will continue to maintain this amount in legal reserves until the appellate process in this case has been completed. We continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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.

Tennessee Business License Tax

Atmos Energy, through its affiliate, AEM, has been involved in a dispute with the Tennessee Department of Revenue (TDOR) regarding sales business tax audits over a period of several years. AEM has challenged the assessment of the business tax. With respect to certain issues, AEM and the TDOR filed competing Partial Motions for Summary Judgment with the Chancery Court. On August 2, 2013, the Chancery Court granted the TDOR's Partial Motion for Summary Judgment and denied AEM's Partial Motion for Summary Judgment. The Company anticipates a decision by the Chancery Court on the remaining issues in fiscal 2014. AEM has been assessed \$6.1 million in business taxes and \$3.7 million in penalties and interest for the period from December 2002 through March 31, 2012. We have accrued what we believe to be an adequate amount for the anticipated resolution of this matter and we will continue to review and if appropriate adjust this reserve until this matter is resolved. We continue to believe 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

We are a party to 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

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. At September 30, 2013, the estimated commitments under these contracts are $230.5 million for fiscal 2014.

Our nonregulated segment has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2013, we were committed to purchase 78.0 Bcf within one year, 21.9 Bcf within one to three years and 1.0 Bcf after three years under indexed contracts. We are committed to purchase 6.1 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $3.32 to $6.36 per Mcf. Purchases under these contracts totaled $1,246.1 million, $978.8 million and $1,498.6 million for 2013, 2012 and 2011.

In addition, 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, 2013 are as follows (in thousands):

2014	$12,662
2015	5,113
2016	743
2017	170
2018	142
Thereafter	356
	$19,186

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.

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 required 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. A number of those regulations have been adopted; we have enacted new procedures and modified existing business practices and contractual arrangements to comply with such regulations. We expect additional regulations to be issued, which should 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 further increased when these expected additional regulations are adopted. We also anticipate that the Commodities Futures Trading Commission will issue additional related reporting and disclosure obligations.

11. Income Taxes

The components of income tax expense from continuing operations for 2013, 2012 and 2011 were as follows:

	2013	2012	2011
	(In thousands)		
Current			
Federal	$—	$631	$(13,298)
State	8,178	6,888	6,841
Deferred			
Federal	124,836	103,971	107,950
State	9,605	(13,237)	5,498
Investment tax credits	(20)	(27)	(172)
	$142,599	$98,226	$106,819

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Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2013, 2012 and 2011 are set forth below:

	2013	2012	2011
	(In thousands)		
Tax at statutory rate of 35%	$130,655	$101,648	$103,743
Common stock dividends deductible for tax reporting	(2,153)	(2,096)	(1,930)
Penalties	153	66	2,292
Recognition (settlement) of uncertain tax positions	1,341	1,831	(4,950)
State taxes (net of federal benefit)	10,687	(5,958)	8,109
Other, net	1,916	2,735	(445)
Income tax expense	$142,599	$98,226	$106,819

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, 2013 and 2012 are presented below:

	2013	2012
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$11,496	$7,906
Customer advances	4,279	4,721
Nonqualified benefit plans	52,051	48,513
Postretirement benefits	63,919	62,802
Treasury lock agreements	—	25,448
Unamortized investment tax credit	6	14
Tax net operating loss and credit carryforwards	206,996	164,419
Difference between book and tax on mark to market accounting	2,271	2,342
Other, net	—	7,223
Total deferred tax assets	341,018	323,388
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,445,450)	(1,254,698)
Pension funding	(23,480)	(32,812)
Gas cost adjustments	(19,182)	(21,806)
Interest rate agreements	(21,726)	—
Cost expensed for tax purposes and capitalized for book purposes	(2,815)	(2,065)
Other, net	(7,115)	—
Total deferred tax liabilities	(1,519,768)	(1,311,381)
Net deferred tax liabilities	$(1,178,750)	$(987,993)
Deferred credits for rate regulated entities	$(51)	$140

At September 30, 2013, we had $10.1 million of federal alternative minimum tax credit carryforwards, $185.3 million of federal net operating loss carryforwards, $11.0 million of state net operating loss carryforwards and $0.6 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. We believe it is more likely than not that the benefit from certain charitable contribution carryforwards will not be realized. In recognition of this risk, we have established a valuation allowance of $1.1 million for deferred tax assets relating to these charitable contribution carryforwards.

At September 30, 2013, we had recorded liabilities associated with uncertain tax positions totaling $3.2 million. The realization of these tax benefits would reduce our income tax expense by approximately $3.2 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 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.

12. 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.

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, 2013 and 2012:

	Natural Gas Distribution (In thousands)	Nonregulated	Total
September 30, 2013			
Assets from risk management activities, current[1]	$1,837	$16,262	$18,099
Assets from risk management activities, noncurrent	109,354	—	109,354
Liabilities from risk management activities, current[1]	(1,543)	—	(1,543)
Liabilities from risk management activities, noncurrent	—	(6,133)	(6,133)
Net assets (liabilities)	$109,648	$10,129	$119,777
September 30, 2012[3]			
Assets from risk management activities, current[2]	$6,934	$17,773	$24,707
Assets from risk management activities, noncurrent	2,283	—	2,283
Liabilities from risk management activities, current[2]	(85,366)	(15)	(85,381)
Liabilities from risk management activities, noncurrent	—	(9,206)	(9,206)
Net assets (liabilities)	$(76,149)	$8,552	$(67,597)

(1) Includes $24.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $8.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.2 million is classified as current risk management assets.

(2) 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.

(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.

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 2012-2013 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 33 percent, or 22.8 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $4.03 per Mcf. We have not designated these financial instruments as hedges.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we buy, sell and deliver natural gas at competitive prices by aggregating and purchasing gas supply, arranging transportation and storage logistics and effectively managing commodity price risk. 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 associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 55 months. We use financial instruments, designated as fair value hedges, to hedge natural gas inventory used in these operations. We also use storage and basis swaps, futures and various over-the-counter and exchange-traded options primarily to protect the economic value of our fixed price and storage books. 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, 2013, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 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 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $350 million out of a total $500 million of senior notes that were issued on January 11, 2013. This offering is discussed in Note 5. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on January 8, 2013 with a payment of $66.6 million to the counterparties due to a decrease in the 30-year Treasury rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the $66.6 million unrealized loss 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.

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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. We recorded an immaterial loss upon settlement of the swap, which was recorded as a component of interest expense as we did not designate the interest rate swap as a hedge.

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 extend through fiscal 2043.

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, 2013, 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, 2013, 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	—	(13,033)
	Cash Flow	—	31,195
	Not designated	29,185	75,683

	29,185	93,845

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, 2013 and 2012. 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 $24.8 million and $23.7 million of cash held on deposit in margin accounts as of September 30, 2013 and 2012 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

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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 14.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2013				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$—	$ 9,094	$9,094
Noncurrent commodity contracts	Deferred charges and other assets	107,512	416	107,928
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(12,173)	(12,173)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,639)	(1,639)
Total		107,512	(4,302)	103,210
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	1,837	65,388	67,225
Noncurrent commodity contracts	Deferred charges and other assets	1,842	40,982	42,824
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(1,543)	(70,876)	(72,419)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(45,892)	(45,892)
Total		2,136	(10,398)	(8,262)
Total Financial Instruments		$109,648	$ (14,700)	$94,948

	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)

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(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.

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, 2013, 2012 and 2011, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $18.2 million, $23.1 million and $24.8 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, 2013, 2012 and 2011 is presented below.

	Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Commodity contracts	$2,165	$30,266	$16,552
Fair value adjustment for natural gas inventory designated as the hedged item	15,938	(5,797)	9,824
Total decrease in purchased gas cost	$18,103	$24,469	$26,376
The decrease in purchased gas cost is comprised of the following:			
Basis ineffectiveness	$(208)	$1,170	$803
Timing ineffectiveness	18,311	23,299	25,573
	$18,103	$24,469	$26,376

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, 2013 and 2011.

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Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2013, 2012 and 2011 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, 2013			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$—	$(10,778)	$(10,778)
Gain arising from ineffective portion of commodity contracts	—	—	97	97
Total impact on purchased gas cost	—	—	(10,681)	(10,681)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(3,489)	—	—	(3,489)
Total impact from cash flow hedges	$(3,489)	$—	$(10,681)	$(14,170)

	Fiscal Year Ended September 30, 2012			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI 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 interest rate agreements reclassified from AOCI into interest expense	(2,009)	—	—	(2,009)
Total impact from cash flow hedges	$(2,009)	$—	$(64,047)	$(66,056)

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI 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 interest rate agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of interest rate agreement 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)

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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, 2013 and 2012. 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	
	2013	2012
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate agreements	$79,963	$(11,458)
Forward commodity contracts	(2,057)	(30,366)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	2,216	1,342
Forward commodity contracts	6,576	38,232
Total other comprehensive income (loss) from hedging, net of tax[1]	$86,698	$(2,250)

(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 interest rate 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, 2013. However, the table below does not include the expected recognition in earnings of the interest rate agreements entered into in October 2012 as those financial instruments have not yet settled.

	Interest Rate Agreements	Commodity Contracts	Total
	(In thousands)		
2014	$(2,686)	$(3,748)	$(6,434)
2015	(804)	(425)	(1,229)
2016	(634)	(163)	(797)
2017	(735)	(109)	(844)
2018	(936)	(31)	(967)
Thereafter	(24,569)	—	(24,569)
Total[1]	$(30,364)	$(4,476)	$(34,840)

(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, 2013, 2012 and 2011 was an increase (decrease) in purchased gas cost of $3.0 million, $(2.5) million and $(1.4) 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.

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13. Accumulated Other Comprehensive Income

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale securities, interest rate agreement cash flow hedges and commodity contract cash flow hedges. Deferred gains (losses) for our available-for-sale securities and commodity contract cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as they are amortized. The following table provides the components of our accumulated other comprehensive income (loss) balances, net of the related tax effects allocated to each component of other comprehensive income.

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2012	$5,661	$(44,273)	$(8,995)	$(47,607)
Other comprehensive income before reclassifications	1,162	79,963	(2,057)	79,068
Amounts reclassified from accumulated other comprehensive income	(1,375)	2,216	6,576	7,417
Net current-period other comprehensive income (loss)	(213)	82,179	4,519	86,485
September 30, 2013	$5,448	$37,906	$(4,476)	$38,878

The following table details reclassifications out of AOCI for the fiscal year ended September 30, 2013. Amounts in parentheses below indicate decreases to net income in the statement of income.

Accumulated Other Comprehensive Income Components	Fiscal Year Ended September 30, 2013 Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$2,166	Operation and maintenance expense
	2,166	Total before tax
	(791)	Tax expense
	$1,375	Net of tax
Cash flow hedges		
Interest rate agreements	$(3,489)	Interest charges
Commodity contracts	(10,778)	Purchased gas cost
	(14,267)	Total before tax
	5,475	Tax benefit
	$(8,792)	Net of tax
Total reclassifications	$(7,417)	Net of tax

14. 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.
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 6.

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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, 2013 and 2012. 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, 2013
	(In thousands)				
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$111,191	$—	$—	$111,191
Nonregulated segment	745	115,135	—	(99,618)	16,262
Total financial instruments	745	226,326	—	(99,618)	127,453
Hedged portion of gas stored underground	44,758	—	—	—	44,758
Available-for-sale securities					
Money market funds	—	4,428	—	—	4,428
Registered investment companies	40,094	—	—	—	40,094
Bonds	—	28,160	—	—	28,160
Total available-for-sale securities	40,094	32,588	—	—	72,682
Total assets	$85,597	$258,914	$—	$(99,618)	$244,893
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$1,543	$—	$—	$1,543
Nonregulated segment	158	130,422	—	(124,447)	6,133
Total liabilities	$158	$131,965	$—	$(124,447)	$7,676

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	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, 2012
	(In thousands)				
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$9,365	$—	$—	$9,365
Nonregulated segment	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	4,563	191,109	—	(186,451)	9,221
Total liabilities	$4,563	$276,734	$—	$(186,451)	$94,846

(1) 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.

(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, 2013 we had $24.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $8.6 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.2 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, 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.

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, 2013				
Domestic equity mutual funds	$27,043	$7,476	$(23)	$34,496
Foreign equity mutual funds	4,536	1,062	—	5,598
Bonds	28,016	168	(24)	28,160
Money market funds	4,428	—	—	4,428
	$64,023	$8,706	$(47)	$72,682
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

At September 30, 2013 and 2012, our available-for-sale securities included $44.5 million and $41.8 million related to assets held in separate rabbi trusts for our supplemental executive retirement plans as discussed in Note 6. At September 30, 2013 we maintained investments in bonds that have contractual maturity dates ranging from October 2013 through December 2019. During the year ended September 30, 2013, we recognized a net gain of $2.2 million on the sale of certain assets in the rabbi trusts.

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 10, 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 further 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

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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, 2013:

	September 30, 2013
	(In thousands)
Carrying Amount	$2,460,000
Fair Value	$2,676,487

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.

16. Discontinued Operations

On April 1, 2013, we completed the sale of substantially all of our natural gas distribution assets and certain related nonregulated assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million, pursuant to an asset purchase agreement executed on August 8, 2012. In connection with the sale, we recognized a pre-tax gain of approximately $8.2 million.

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.

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.

The following table presents statement of income data related to discontinued operations in our Georgia, Missouri, Illinois and Iowa service areas.

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	Year Ended September 30		
	2013	2012	2011
	(In thousands)		
Operating revenues	$37,962	$114,703	$141,227
Purchased gas cost	21,464	62,902	83,537
Gross profit	16,498	51,801	57,690
Operating expenses	5,858	24,174	27,362
Operating income	10,640	27,627	30,328
Other nonoperating income	548	611	57
Income from discontinued operations before income taxes	11,188	28,238	30,385
Income tax expense	3,986	10,066	12,372
Income from discontinued operations	7,202	18,172	18,013
Gain on sale of discontinued operations, net of tax	5,294	6,349	—
Net income from discontinued operations	$12,496	$24,521	$18,013

The following table presents balance sheet data related to assets held for sale. At September 30, 2013 we did not have any assets or liabilities held for sale. At September 30, 2012 assets held for sale include assets and liabilities associated with our Georgia operations.

	September 30, 2012
	(In thousands)
Net plant, property & equipment	$142,865
Gas stored underground	4,688
Other current assets	6,931
Deferred charges and other assets	