ATMOS ENERGY CORP
Form 10-K
November 06, 2014
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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, 2014
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 (IRS employer
incorporation or organization) 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, 2014, was $4,659,809,695.
As of October 31, 2014, the registrant had 100,393,038 shares of common stock outstanding.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 4, 2015 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
KPSC	Kentucky Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
Mid-Tex Cities	Represents all incorporated cities other than Dallas, 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 pipeline 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.

During fiscal 2012 and 2013, we sold our natural gas distribution operations in four states to streamline our regulated operations. In August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers, and in April 2013, we completed the sale of our natural gas distribution operations in Georgia, representing approximately 64,000 customers.

Our nonregulated businesses 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 six 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 regulated distribution segment, which includes our regulated distribution and related sales operations
- The regulated pipeline segment, which includes the 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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Regulated Distribution Segment Overview

Our regulated 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. 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, 2014, we held 1,003 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	1,609,920
Kentucky/Mid-States	Kentucky	230	177,811
	Tennessee		137,989
	Virginia		23,261
Louisiana	Louisiana	300	353,079
West Texas	Amarillo, Lubbock, Midland	80	302,815
Mississippi	Mississippi	110	265,762
Colorado-Kansas	Colorado	170	113,006
	Kansas		131,426

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 distribution operating revenues fluctuate with the cost of gas that we purchase, 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 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.

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 2014 were ConocoPhillips Company, Devon Gas Services, L.P., Enbridge Marketing (US) Inc., Enterprise Products Operating LLC, Iberdrola Energy Services, LLC, NJR Energy

Services Company, Targa Gas Marketing LLC, Tenaska Gas Storage, LLC, Tenaska Marketing Ventures, Texla Energy Management, Inc. and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

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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 distribution operations in fiscal 2014 was on January 6, 2014, when sales to customers reached approximately 3.5 Bcf.

Currently, our 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 Pipeline Segment Overview

Our regulated pipeline 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 Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Through it, we transport natural gas to our Mid-Tex Division and to third parties and manage five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements. This segment represents approximately 30 percent of our consolidated operations.

Gross profit earned from transportation for our Mid-Tex Division, other local distribution companies and 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.

Nonregulated Segment Overview

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation, and typically 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 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:

- Formula rate mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately 77 percent of our distribution gross margin.

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- Approximately 90 percent of our capital expenditures are recovered within six months.
- Accelerated recovery of capital for approximately 91 percent of our regulated distribution gross margin.
- Enhanced rate recovery 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.
- Enhanced rate design in our Mid-Tex and West Texas Divisions (which represent approximately 56 percent of our regulated distribution segment operating income) to increase the customer base charge and decrease the consumption charge applied to customer usage. This rate design reduces our dependence on customer consumption in these divisions, which should enable these divisions to earn operating income more ratably over the fiscal year.
- WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our distribution gross margin.
- The ability to recover the gas cost portion of bad debts for approximately 76 percent of our distribution gross margin.

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	05/01/2014	1,169,893	9.36%	N/A	11.80%
Colorado-Kansas	Colorado	08/26/2014	111,297	8.04%	48/52	9.72%
	Kansas	09/04/2014	177,563	7.75%	47/53	9.10%
Kentucky/Mid-States	Kentucky	04/22/2014	252,738	7.71%	51/49	9.80%
	Tennessee	11/08/2012	201,359	8.28%	49/51	10.10%
	Virginia	09/09/2014	37,456	7.94%	46/54	9.00% - 10.00%
Louisiana	Trans LA	04/01/2014	109,940	7.79%	52/48	10.00% - 10.80%
	LGS	07/01/2014	309,432	7.79%	49/51	9.80%
Mid-Tex Cities	Texas	11/01/2013	1,672,286(3)	8.59%	(2)	10.50%
Mid-Tex — Dallas	Texas	06/01/2014	1,798,530(3)	8.31%	48/52	10.10%
Mississippi	Mississippi	01/07/2014	298,466	8.18%	49/51	9.95%
West Texas(4)	Texas	04/01/2014	324,264	(2)	(2)	(2)

Division	Jurisdiction	Bad Debt Rider(5)	Annual Rate Mechanism	Infrastructure Mechanism	Performance-Based Rate Program(6)	WNA Period
Atmos Pipeline — Texas	Texas	No	No	Yes	N/A	N/A
Colorado-Kansas	Colorado	No	No	No	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	Yes	No	December-March
	LGS	No	Yes	Yes	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(4)	Texas	Yes	Yes	Yes	No	October-May

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(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) 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.

(4) On April 1, 2014, a rate case settlement approved by the West Texas Cities reestablished an annual rate mechanism for all West Texas Division cities except Amarillo, Channing, Dalhart and Lubbock.

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

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

Although substantial progress has been made in recent years by improving rate design and recovery of investment 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 and pursue tariffs that reduce regulatory lag associated with investments. 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, 2014, 2013 and 2012 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 $93.3 million, $98.1 million and $30.7 million, became effective in fiscal 2014, 2013 and 2012, as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2014	2013	2012
	(In thousands)		
Infrastructure programs	$51,681	$30,936	$19,172
Annual rate filing mechanisms	20,068	9,152	7,044
Rate case filings	21,819	56,700	4,309
Other ratemaking activity	(226)	1,322	167
	$93,342	$98,110	$30,692

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Additionally, the following ratemaking efforts were initiated during fiscal 2014 but had not been completed as of September 30, 2014:

Division	Rate Action	Jurisdiction	Operating Income Requested (In thousands)
Kentucky/Mid-States	PRP(1)	Kentucky	$4,317
	PRP(2)	Virginia	170
Mid-Tex Division	RRM(3)	Mid-Tex Cities	33,415
Mississippi	Stable Rate Filing	Mississippi	8,922
	SGR(4)	Mississippi	782
			$47,606

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Kentucky PRP was implemented on October 10, 2014.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Virginia PRP was implemented on October 1, 2014.

(3) Mid-Tex Cities RRM rates were put into effect on June 1, 2014, subject to refund. The Company appealed the Mid-Tex Cities decision to deny the 2013 RRM increase to the Texas Railroad Commission on May 30, 2014. A proposal for decision is expected before the end of the calendar year.

(4) The Mississippi Supplemental Growth Rider (SGR) permits the Company to pursue up to $5.0 million of eligible industrial growth projects beyond the division's normal main extension policies. This is the second year of the SGR program.

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Our recent ratemaking activity is discussed in greater detail below.

Infrastructure Programs

As discussed above in "Regulated Distribution Segment Overview" and "Regulated Pipeline 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, Louisiana and Virginia. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2014, 2013 and 2012:

Division	Period End	Incremental Net Utility Plant Investment (In thousands)	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Infrastructure Programs:				
West Texas[(1)]	12/2013	$58,841	$858	06/17/2014
Mid-Tex - Environs[(2)]	12/2013	203,714	881	05/22/2014
Atmos Pipeline — Texas	12/2013	265,050	45,589	05/06/2014
Colorado-Kansas - Kansas	09/2013	9,323	882	02/01/2014
Kentucky/Mid-States - Kentucky	09/2014	17,488	2,493	10/01/2013
Kentucky/Mid-States - Virginia	09/2014	1,587	210	10/01/2013
Mid-Tex - Environs[(2)]	12/2012	164,681	768	10/01/2013
Total 2014 Infrastructure Programs		$720,684	$51,681	
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[(3)(4)]	09/2011	6,519	1,079	10/01/2012
Kentucky/Mid-States — Kentucky[(4)]	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)[(2)]	12/2011	$145,671	$744	06/26/2012
Atmos Pipeline — Texas	12/2011	87,210	14,684	04/10/2012
Kentucky/Mid-States — Georgia[(3)(4)]	09/2010	7,160	1,215	10/01/2011
Kentucky/Mid-States — Kentucky[(4)]	09/2012	17,347	2,529	10/01/2011
Total 2012 Infrastructure Programs		$257,388	$19,172	

(1) Incremental net utility plant investment represents the system-wide incremental investment for the West Texas Division. The increase in annual operating income is for the unincorporated areas of the West Texas Division only.

(2) 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.

(3) 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.

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

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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 an annual 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 formula rate filing mechanisms in our Louisiana and Mississippi divisions and in a portion of our Texas divisions. The annual rate filing mechanism is referred to as Dallas annual rate review (DARR) and rate review mechanisms (RRM) in our Mid-Tex Division, as the RRM in our West Texas Division, as 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 formula rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2014 Filings:				
Louisiana	LGS	12/31/2013	$1,383	07/01/2014
Mid-Tex	City of Dallas	09/30/2013	5,638	06/01/2014
Louisiana	Trans LA	09/30/2013	550	04/01/2014
Mid-Tex	Mid-Tex Cities	12/31/2012	12,497	11/01/2013
Total 2014 Filings			$20,068	
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	

(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.

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.

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:

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Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Rate Case Filings:			
Kentucky/Mid-States	Virginia	$976	09/09/2014
Colorado-Kansas	Kansas	2,571	09/04/2014
Colorado-Kansas	Colorado	2,400	08/26/2014
Kentucky/Mid-States	Kentucky	5,823	04/22/2014
West Texas	Texas	8,440	04/01/2014
Colorado-Kansas	Colorado	1,609	03/01/2014
Total 2014 Rate Case Filings		$21,819	
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	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2014, 2013 and 2012:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[(1)]	$(226)	02/01/2014
Total 2014 Other Rate Activity			$(226)	
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	

(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.

Other Regulation

Each of our regulated distribution divisions and our regulated pipeline 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 regulated operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites.

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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 regulated 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 pipeline operations historically faced competition from other existing intrastate pipelines seeking to provide or arrange transportation, storage and other services for customers. 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, 2014, we had 4,761 employees, consisting of 4,650 employees in our regulated operations and 111 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 2014, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

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ITEM 1A. Risk Factors.

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

The 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 regulated distribution and regulated pipeline segments are subject to regulatory oversight from various state and local regulatory authorities in the eight states that we serve in our regulated distribution and pipeline segments. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party interveners. In the normal course of business, as a regulated entity, we often need 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.

A deterioration in economic conditions could adversely affect our customers and negatively impact our financial results.

Any adverse changes in economic conditions in the United States, especially in the states in which we operate, similar to the economic downturn we experienced for several years beginning in 2008 could adversely affect the financial resources of many domestic households and lead to an increase in mortgage defaults and significant decreases in the values of our customers' homes and investment assets. As a result, our customers could seek to use even less gas and make it more difficult for them to pay their gas bills. This would likely lead to slower collections and higher than normal levels of accounts receivable. This, in turn, would probably increase our financing requirements and bad debt expense. Additionally, should economic conditions deteriorate, our industrial customers could seek alternative energy sources, which could result in lower sales volumes.

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

Inflation has continued to cause 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 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.

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In addition, 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 (i) commodity price volatility caused by market supply and demand dynamics, counterparty performance or counterparty creditworthiness, and (ii) interest rate risk.

Our regulated operations are generally insulated from commodity price risk through its purchased gas cost mechanisms. Although our nonregulated operations represent only about 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.

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.

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

Over 50 percent of our regulated distribution customers and most of our regulated pipeline 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, weather patterns and regulatory decisions by state and local regulatory authorities in Texas.

Our operations are subject to increased competition.

In residential and commercial customer markets, our regulated 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 pipeline 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 regulated 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 regulated distribution and regulated pipeline 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 pipeline 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 regulated 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, 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. The impact of additional costs incurred by the health insurance industry arising from the implementation of HCR, which are likely to be passed on to 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 due to sustained declines in equity markets or a reduction in bond yields could increase the costs of our 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; (ii) various actuarial calculations and assumptions which may differ materially from actual results due primarily to changing market and economic conditions, including changes in interest rates, and higher or lower withdrawal rates; and (iii) future government regulation.

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.

The inability to continue to hire, train and retain operational, technical and managerial personnel could adversely affect our results of operations.

The average age of the employee base of Atmos Energy has been increasing for a number of years, with a number of employees becoming eligible to retire within the next five to 10 years. If we were unable to hire appropriate personnel to fill future needs, the Company could encounter operating challenges and increased costs, primarily due to a loss of knowledge, errors due to inexperience or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from the increased use of contractors to replace retiring employees, loss of productivity or increased

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safety compliance issues. The inability to hire, train and retain new operational, technical and managerial personnel adequately and to transfer institutional knowledge and expertise could adversely affect our ability to manage and operate our business. If we were unable to hire, train and retain appropriately qualified personnel, our results of operations could be adversely affected.

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 have continued to face 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 laws and 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.

The operations and financial results of the Company could be adversely impacted as a result of climate changes or related additional legislation or regulation in the future.

To the extent climate changes occur, our businesses could be adversely impacted, although we believe it is likely that any such resulting impacts would occur very gradually over a long period of time and thus would be difficult to quantify with any degree of specificity. To the extent climate changes would result in warmer temperatures in our service territories, financial results from our regulated distribution segment could be adversely affected through lower gas volumes and revenues, with our regulated pipeline segment also likely experiencing lower volumes and revenues as well. Such climate changes could also cause shifts in population, including customers moving away from our service territories near the Gulf Coast in Louisiana and Mississippi. Another possible climate change would be more frequent and more severe weather events, such as hurricanes and tornados, which could increase our costs to repair damaged facilities and restore service to our customers. If we were unable to deliver natural gas to our customers, our financial results would be impacted by lost revenues, and we generally would have to seek approval from regulators to recover restoration costs. To the extent we would be unable to recover those costs, or if higher rates resulting from our recovery of such costs would result in reduced demand for our services, our future business, financial condition or financial results could be adversely impacted. In addition, 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.

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

Our regulated distribution and regulated pipeline businesses involve a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by our general liability and property insurance, which policies are subject to certain limits and deductibles, 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 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 become 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, 2014, in our regulated distribution segment, we owned an aggregate of 67,725 miles of underground distribution and transmission mains throughout our 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 pipeline segment we owned 5,410 miles of gas transmission and gathering lines as well as 113 miles of transmission and gathering lines through our nonregulated segment.

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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, 2014:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)[1]	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Regulated 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	1,907,571	2,442,917	4,350,488	31,000
Total	9,589,267	11,065,200	20,654,467	181,100
Regulated Pipeline Segment — Texas	46,083,549	15,878,025	61,961,574	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	59,550,299	30,484,198	90,034,497	1,539,600

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

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2014:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Regulated Distribution Segment			
	Colorado-Kansas Division	5,261,909	118,889
	Kentucky/Mid-States Division	11,081,603	245,766
	Louisiana Division	2,663,539	157,743
	Mid-Tex Division	2,500,000	125,000
	Mississippi Division	3,895,429	168,322
	West Texas Division	4,000,000	126,000
Total		29,402,480	941,720
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		39,103,349	1,260,164

(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.

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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 2014 and 2013 are listed below. The high and low prices listed are the closing NYSE quotes, as reported on the NYSE composite tape, for shares of our common stock:

	Fiscal 2014			Fiscal 2013		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$47.06	$41.08	$0.37	$36.86	$33.20	$0.35
March 31	48.01	44.19	0.37	42.69	35.11	0.35
June 30	53.40	46.94	0.37	44.87	38.59	0.35
September 30	52.68	47.01	0.37	45.19	39.40	0.35
			$1.48			$1.40

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, 2014 was 15,751. 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 2014 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, 2009 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.

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

	Cumulative Total Return					
	9/30/2009	9/30/2010	9/30/2011	9/30/2012	9/30/2013	9/30/2014
Atmos Energy Corporation	100.00	108.92	126.03	144.89	178.67	206.41
S&P 500	100.00	110.16	111.42	145.07	173.13	207.30
Peer Group	100.00	132.53	155.94	188.48	221.32	266.62

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, 2014.

	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	—	$ —	845,139
Total equity compensation plans approved by security holders	—	—	845,139
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	845,139

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

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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 2014. At September 30, 2014, 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				
	2014	2013	2012[1]	2011[1]	2010
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$4,940,916	$3,875,460	$3,436,162	$4,286,435	$4,661,060
Gross profit	$1,582,426	$1,412,050	$1,323,739	$1,300,820	$1,314,136
Income from continuing operations	$289,817	$230,698	$192,196	$189,588	$189,851
Net income	$289,817	$243,194	$216,717	$207,601	$205,839
Diluted income per share from continuing operations	$2.96	$2.50	$2.10	$2.07	$2.03
Diluted net income per share	$2.96	$2.64	$2.37	$2.27	$2.20
Cash dividends declared per share	$1.48	$1.40	$1.38	$1.36	$1.34
Financial Condition					
Net property, plant and equipment[2]	$6,725,906	$6,030,655	$5,475,604	$5,147,918	$4,793,075
Total assets	$8,594,704	$7,934,268	$7,495,675	$7,282,871	$6,763,791
Capitalization:					
Shareholders’ equity	$3,086,232	$2,580,409	$2,359,243	$2,255,421	$2,178,348
Long-term debt (excluding current maturities)	2,455,986	2,455,671	1,956,305	2,206,117	1,809,551
Total capitalization	$5,542,218	$5,036,080	$4,315,548	$4,461,538	$3,987,899

(1) Financial results for fiscal years 2012 and 2011 reflect a $5.3 million and a $30.3 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.

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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 commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 regulated distribution business; increased costs of providing health care benefits along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; 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 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 regulated distribution and pipeline 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	Decisions of regulatory authorities Issuance of new regulations Assessing the probability of the recoverability of

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.	deferred costs

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Unbilled Revenue	We follow the revenue accrual method of accounting for regulated 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
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	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 Impact of regulation

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 retirement is estimated based upon our annual review of our participant census information as of the measurement date.

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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
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

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 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.	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
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	General economic and market conditions Projected timing and amount of future discounted cash flows

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.	Judgment in the evaluation of relevant data

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RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation strives to operate its businesses safely and reliably while delivering superior shareholder value. To achieve this objective, we are investing in our infrastructure and are seeking to achieve positive rate outcomes that benefit both our customers and the Company. During fiscal 2014, we earned $289.8 million, or $2.96 per diluted share, which represents a 19 percent increase in net income and a 12 percent increase in diluted net income per share over fiscal 2013, primarily due to positive rate outcomes combined with increased gross profit associated with weather that was 20 percent colder than the prior-year period. The colder than normal weather increased market demand for natural gas, which drove higher price volatility, particularly during our second fiscal quarter.

Capital expenditures for fiscal 2014 totaled $835.3 million. Approximately 80 percent was invested to improve the safety and reliability of our distribution and transportation systems, and a significant portion of this investment was incurred under regulatory mechanisms that reduce lag to six months or less. Fiscal 2013 spending under these and other mechanisms enabled the Company to complete 18 regulatory filings that should increase annual operating income from regulated operations by $93.3 million. We plan to continue to fund our growth through the use of operating cash flows and debt and equity securities, while maintaining a balanced capital structure.

During fiscal 2014 and early fiscal 2015, we undertook several initiatives to strengthen our balance sheet and improve our liquidity. On February 18, 2014, we completed the sale of 9,200,000 shares of common stock under our shelf registration statement, generating net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

On August 22, 2014, we amended our $950 million credit facility to increase the committed loan amount from $950 million to $1.25 billion and extend the expiration date to August 22, 2019. The facility retains the $250 million accordion feature, which allows for an increase in the total committed loan amount to $1.5 billion. Our debt-to-capitalization ratio as of September 30, 2014 was 46.2 percent and our liquidity remained strong with over $1 billion of capacity from our short-term facilities.

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million 4.95% 10-year unsecured senior notes at maturity on October 15, 2014.

As a result of the continued contribution and stability of our regulated earnings, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 5.4 percent for fiscal 2015.

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Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2014, 2013 and 2012.

	For the Fiscal Year Ended September 30		
	2014	2013	2012
	(In thousands, except per share data)		
Operating revenues	$4,940,916	$3,875,460	$3,436,162
Gross profit	1,582,426	1,412,050	1,323,739
Operating expenses	971,077	910,171	877,499
Operating income	611,349	501,879	446,240
Miscellaneous expense	(5,235)	(197)	(14,644)
Interest charges	129,295	128,385	141,174
Income from continuing operations before income taxes	476,819	373,297	290,422
Income tax expense	187,002	142,599	98,226
Income from continuing operations	289,817	230,698	192,196
Income from discontinued operations, net of tax	—	7,202	18,172
Gain on sale of discontinued operations, net of tax	—	5,294	6,349
Net income	$289,817	$243,194	$216,717
Diluted net income per share from continuing operations	$2.96	$2.50	$2.10
Diluted net income per share from discontinued operations	$—	$0.14	$0.27
Diluted net income per share	$2.96	$2.64	$2.37

Regulated operations contributed 89 percent, 95 percent and 97 percent to our consolidated net income from continuing operations for fiscal years 2014, 2013 and 2012. 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		
	2014	2013	2012
	(In thousands)		
Regulated distribution segment	$171,585	$150,856	$123,848
Regulated pipeline segment	86,191	68,260	63,059
Nonregulated segment	32,041	11,582	5,289
Net income from continuing operations	289,817	230,698	192,196
Net income from discontinued operations	—	12,496	24,521
Net income	$289,817	$243,194	$216,717

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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		
	2014	2013	2012
	(In thousands, except per share data)		
Regulated operations	$257,776	$219,116	$186,907
Nonregulated operations	32,041	11,582	5,289
Net income from continuing operations	289,817	230,698	192,196
Net income from discontinued operations	—	12,496	24,521
Net income	$289,817	$243,194	$216,717
Diluted EPS from continuing regulated operations	$2.63	$2.38	$2.04
Diluted EPS from nonregulated operations	0.33	0.12	0.06
Diluted EPS from continuing operations	2.96	2.50	2.10
Diluted EPS from discontinued operations	—	0.14	0.27
Consolidated diluted EPS	$2.96	$2.64	$2.37

We reported net income of $289.8 million, or $2.96 per diluted share for the year ended September 30, 2014, compared with net income of $243.2 million or $2.64 per diluted share in the prior year. Income from continuing operations was $289.8 million, or $2.96 per diluted share compared with $230.7 million, or $2.50 per diluted share in the prior-year period. In the prior year, income from discontinued operations was $12.5 million or $0.14 per diluted share, which included the gain on sale of substantially all our assets in Georgia of $5.3 million. Unrealized gains in our nonregulated operations during the current year increased net income by $5.8 million or $0.06 per diluted share compared with net gains recorded in the prior year of $5.3 million or $0.05 per diluted share. 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 $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 fiscal 2012. Income from continuing operations in fiscal 2013 was $230.7 million, or $2.50 per diluted share compared with $192.2 million, or $2.10 per diluted share in fiscal 2012. Income from discontinued operations was $12.5 million or $0.14 per diluted share for the year ended September 30, 2013, 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 fiscal 2012. Unrealized gains in our nonregulated operations during fiscal 2013 increased net income by $5.3 million or $0.05 per diluted share compared with net losses recorded in fiscal 2012 of $5.0 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. 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. 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.

Regulated Distribution Segment

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

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

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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. Currently, gas cost risk has been mitigated by rate design that allows us to collect from our customers the gas cost portion of our bad debt expense on approximately 76 percent of our residential and commercial margins.
During fiscal 2014, we completed 17 regulatory proceedings in our regulated distribution segment, which should result in a $47.8 million increase in annual operating income.
In August 2012, we completed the sale of our regulated distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers and in April 2013, we completed the sale of our Georgia regulated distribution operations, representing approximately 64,000 customers.

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Review of Financial and Operating Results

Financial and operational highlights for our regulated distribution segment for the fiscal years ended September 30, 2014, 2013 and 2012 are presented below.

	For the Fiscal Year Ended September 30				
	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(In thousands, unless otherwise noted)				
Gross profit	$1,176,515	$1,081,236	$1,022,743	$95,279	$58,493
Operating expenses	791,947	738,143	718,282	53,804	19,861
Operating income	384,568	343,093	304,461	41,475	38,632
Miscellaneous income (expense)	(381)	2,535	(12,657)	(2,916)	15,192
Interest charges	94,918	98,296	110,642	(3,378)	(12,346)
Income from continuing operations before income taxes	289,269	247,332	181,162	41,937	66,170
Income tax expense	117,684	96,476	57,314	21,208	39,162
Income from continuing operations	171,585	150,856	123,848	20,729	27,008
Income from discontinued operations, net of tax	—	7,202	18,172	(7,202)	(10,970)
Gain on sale of discontinued operations, net of tax	—	5,649	6,349	(5,649)	(700)
Net Income	$171,585	$163,707	$148,369	$7,878	$15,338
Consolidated regulated distribution sales volumes from continuing operations — MMcf	317,320	269,162	244,466	48,158	24,696
Consolidated regulated distribution transportation volumes from continuing operations — MMcf	134,483	123,144	128,222	11,339	(5,078)
Consolidated regulated distribution throughput from continuing operations — MMcf	451,803	392,306	372,688	59,497	19,618
Consolidated regulated distribution throughput from discontinued operations — MMcf	—	4,731	18,295	(4,731)	(13,564)
Total consolidated regulated distribution throughput — MMcf	451,803	397,037	390,983	54,766	6,054
Consolidated regulated distribution average transportation revenue per Mcf	$0.48	$0.46	$0.43	$0.02	$0.03
Consolidated regulated distribution average cost of gas per Mcf sold	$5.94	$4.91	$4.64	$1.03	$0.27

Fiscal year ended September 30, 2014 compared with fiscal year ended September 30, 2013

Income from continuing operations for our regulated distribution segment increased 14 percent, primarily due to a $95.3 million increase in gross profit, partially offset by a $53.8 million increase in operating expenses. The year to date increase in gross profit primarily reflects:

- a $35.3 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky, West Texas and Louisiana service areas.
- a $14.3 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our Mid-Tex and West Texas Divisions.
- a $27.5 million increase in revenue-related taxes, primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $28.4 million increase in the related tax expense.
- a $13.8 million increase related to increased customer count, higher transportation, late payment and installment plan revenues.

The $53.8 million increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to the following:

- a $28.4 million increase due to the aforementioned increase in revenue-related taxes.
- a $12.8 million increase in depreciation expense.

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- a $12.7 million net increase in employee-related expenses, due to lower labor capitalization rates, increased benefit costs and increased variable compensation expense.
- a $4.2 million increase in the provision for doubtful accounts.

The $21.2 million increase in income tax expense was primarily due to increased income from continuing operations before income taxes as well as an increase of approximately $7.0 million in our deferred tax asset valuation allowance due to the uncertainty in the company's ability to utilize certain charitable contribution carryforwards before they expire.

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

The $58.5 million period-over-period increase in regulated 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.
- $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 of fiscal 2013.

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 fiscal 2012, 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.

The following table shows our operating income from continuing operations by regulated distribution division, in order of total rate base, for the fiscal years ended September 30, 2014, 2013 and 2012. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

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	For the Fiscal Year Ended September 30				
	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(In thousands)				
Mid-Tex	$187,265	$158,900	$142,755	$28,365	$16,145
Kentucky/Mid-States	55,968	46,164	32,185	9,804	13,979
Louisiana	56,648	52,125	48,958	4,523	3,167
West Texas	29,250	28,085	27,875	1,165	210
Mississippi	28,473	29,112	27,369	(639)	1,743
Colorado-Kansas	28,077	25,478	23,898	2,599	1,580
Other	(1,113)	3,229	1,421	(4,342)	1,808
Total	$384,568	$343,093	$304,461	$41,475	$38,632

Regulated Pipeline Segment

Our regulated pipeline segment consists of the 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 Barnett Shale, 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.

Our regulated pipeline segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in APT's 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 determine the market value for transportation services between those geographic areas.

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 transporter of natural gas for our Mid-Tex Division.

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

Review of Financial and Operating Results

Financial and operational highlights for our regulated pipeline segment for the fiscal years ended September 30, 2014, 2013 and 2012 are presented below.

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	For the Fiscal Year Ended September 30				
	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$227,230	$179,628	$162,808	$47,602	$16,820
Third-party transportation	76,109	66,939	64,158	9,170	2,781
Storage and park and lend services	5,344	5,985	6,764	(641)	(779)
Other	9,776	16,348	13,621	(6,572)	2,727
Gross profit	318,459	268,900	247,351	49,559	21,549
Operating expenses	145,640	129,047	118,527	16,593	10,520
Operating income	172,819	139,853	128,824	32,966	11,029
Miscellaneous expense	(3,181)	(2,285)	(1,051)	(896)	(1,234)
Interest charges	36,280	30,678	29,414	5,602	1,264
Income before income taxes	133,358	106,890	98,359	26,468	8,531
Income tax expense	47,167	38,630	35,300	8,537	3,330
Net income	$86,191	$68,260	$63,059	$17,931	$5,201
Gross pipeline transportation volumes — MMcf	714,464	649,740	640,732	64,724	9,008
Consolidated pipeline transportation volumes — MMcf	493,360	467,178	466,527	26,182	651

Fiscal year ended September 30, 2014 compared with fiscal year ended September 30, 2013

Net income for our regulated pipeline segment increased 26 percent, primarily due to a $49.6 million increase in gross profit. The increase in gross profit primarily reflects a $38.5 million increase in rates from the Gas Reliability Infrastructure Program (GRIP) filings approved by the Railroad Commission of Texas (RRC) in fiscal 2014 and 2013 coupled with a $4.7 million increase associated with higher transportation volumes and basis spreads driven by colder weather.

The Atmos Pipeline — Texas 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 the non-regulated annual revenue of Atmos Pipeline — Texas and a pre-defined base credit. The annual adjustment mechanism expired on June 30, 2013. On January 1, 2014, the RRC approved the extension of the annual adjustment mechanism retroactive to July 1, 2013, which will stay in place until the completion of the next Atmos Pipeline — Texas rate case. As a result of this decision, during fiscal 2014, we recognized a $1.8 million increase in gross profit for the application of the annual adjustment mechanism, for the period July 1, 2013 to September 30, 2013.

Operating expenses increased $16.6 million primarily due to the following:

- a $10.1 million increase in pipeline and right-of-way maintenance activities.
- a $5.7 million increase in depreciation expense associated with increased capital investments.
- a $2.4 million increase due to higher employee-related expenses, partially offset by
- a $6.7 million refund received as a result of the completion of a state use tax audit.

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

The $21.5 million increase in regulated pipeline gross profit compared to the prior-year period was primarily a result of the GRIP filings approved by the 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.

Nonregulated Segment

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

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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 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, 2014, 2013 and 2012 are presented below.

	For the Fiscal Year Ended September 30				
	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$39,529	$39,839	$46,578	$(310)	$(6,739)
Storage and transportation services	14,696	14,641	13,382	55	1,259
Other	24,170	(103)	3,179	24,273	(3,282)
Total realized margins	78,395	54,377	63,139	24,018	(8,762)
Unrealized margins	9,560	8,954	(8,015)	606	16,969
Gross profit	87,955	63,331	55,124	24,624	8,207
Operating expenses, excluding asset impairment	33,993	44,404	36,886	(10,411)	7,518
Asset impairment	—	—	5,288	—	(5,288)
Operating income	53,962	18,927	12,950	35,035	5,977
Miscellaneous income	2,216	2,316	1,035	(100)	1,281
Interest charges	1,986	2,168	3,084	(182)	(916)
Income from continuing operations before income taxes	54,192	19,075	10,901	35,117	8,174
Income tax expense	22,151	7,493	5,612	14,658	1,881
Income from continuing operations	32,041	11,582	5,289	20,459	6,293
Loss on sale of discontinued operations, net of tax	—	(355)	—	355	(355)
Net income	$32,041	$11,227	$5,289	$20,814	$5,938
Gross nonregulated delivered gas sales volumes — MMcf	439,014	396,561	400,512	42,453	(3,951)
Consolidated nonregulated delivered gas sales volumes — MMcf	377,441	343,669	351,628	33,772	(7,959)
Net physical position (Bcf)	9.3	12.0	18.8	(2.7)	(6.8)

Fiscal year ended September 30, 2014 compared with fiscal year ended September 30, 2013

Net income for our nonregulated segment increased 185 percent from the prior year due to higher gross profit and decreased operating expenses.

The $24.6 million period-over-period increase in gross profit was primarily due to a $24.0 million increase in realized margins. The increase in realized margins reflects:

- A $24.3 million increase in other realized margins due to the acceleration of physical withdrawals into the second quarter from future periods to capture gross profit margin during periods of increased natural gas price volatility caused by strong market demand as a result of significantly colder weather during the second quarter. This modification in the execution strategy resulted in the establishment of new positions that were expected to settle in the latter half of fiscal 2014 and beyond. The positions that settled during the fourth quarter of fiscal 2014 were settled during a period of falling prices, which further increased realized margins during fiscal 2014. In contrast, losses were incurred from storage optimization activities in the prior year largely due to unfavorable changes in market prices relative to the execution strategy in place at that time.
- A $0.3 million decrease in gas delivery and related services margins. Consolidated sales volumes increased ten percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. However, gas delivery per-unit margins decreased from ten cents per Mcf in the prior-year period to 9 cents per Mcf due primarily to losses incurred during the second quarter to meet peaking requirements for certain customers

during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Operating expenses decreased $10.4 million, primarily due to lower legal expenses related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 10 to the financial statements.

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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 fiscal 2012. 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.

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.

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 capital structure to ensure that we (i) have sufficient liquidity for our short-term and long-term needs in a cost-effective manner and (ii) maintain a balanced capital structure with a debt-to-capitalization ratio in a target range of 50 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1 billion of capacity from our short-term facilities.

The following table presents our capitalization as of September 30, 2014 and 2013:

	September 30					
	2014			2013		
	(In thousands, except percentages)					
Short-term debt	$196,695	3.4	%	$367,984	6.8	%
Long-term debt	2,455,986	42.8	%	2,455,671	45.4	%
Shareholders' equity	3,086,232	53.8	%	2,580,409	47.8	%
Total capitalization, including short-term debt	$5,738,913	100.0	%	$5,404,064	100.0	%

Total debt as a percentage of total capitalization, including short-term debt, was 46.2 percent and 52.2 percent at September 30, 2014 and 2013.

Going forward, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2014 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 primarily through the use of long-term debt securities and, to a lesser extent, equity.

To support our capital market activities, we have filed a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes. On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million 4.95% senior unsecured notes. In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with this issuance at 3.129%, which reduced the effective rate for this issuance to 4.086%. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014. After giving effect to these issuances, $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

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On August 22, 2014, we amended our $950 million credit facility to increase the committed loan amount from $950 million to $1.25 billion and extend the expiration date to August 22, 2019. The amended facility retains the $250 million accordion feature which allows for an increase in the total committed loan amount to $1.5 billion.
Additionally, we plan to issue new unsecured senior notes to replace $250 million and $450 million of unsecured senior notes that will mature in fiscal 2017 and fiscal 2019. During fiscal 2014, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the fiscal 2019 issuances at 3.857%. In fiscal 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the fiscal 2017 issuances at 3.367%.
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.
We believe the liquidity provided by our fiscal 2014 equity issuance, 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 2015.

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.
Cash flows from operating, investing and financing activities for the years ended September 30, 2014, 2013 and 2012 are presented below.

	For the Fiscal Year Ended September 30				
	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$739,986	$613,127	$586,917	$126,859	$26,210
Investing activities	(837,576)	(696,914)	(609,260)	(140,662)	(87,654)
Financing activities	73,649	85,747	(44,837)	(12,098)	130,584
Change in cash and cash equivalents	(23,941)	1,960	(67,180)	(25,901)	69,140
Cash and cash equivalents at beginning of period	66,199	64,239	131,419	1,960	(67,180)
Cash and cash equivalents at end of period	$42,258	$66,199	$64,239	$(23,941)	$1,960

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 regulated distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.
Fiscal Year ended September 30, 2014 compared with fiscal year ended September 30, 2013
For the fiscal year ended September 30, 2014, we generated operating cash flow of $740.0 million from operating activities compared with $613.1 million in the prior year. The year-over-year increase reflects higher operating results from colder weather and rate increases combined with the timing of customer collections and vendor payments.
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 fiscal 2012. 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 fiscal 2013.
Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects in our regulated operations, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide regulated distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines

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and, more recently, expand our intrastate pipeline network. Over the last two fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system.

In executing our regulatory strategy, we 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. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas regulated distribution divisions and our Atmos Pipeline–Texas Division have rate tariffs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

Over the next five years, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2014 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, 2014, we incurred $835.3 million for capital expenditures compared with $845.0 million for the fiscal year ended September 30, 2013 and $732.9 million for the fiscal year ended September 30, 2012.

Fiscal Year ended September 30, 2014 compared with fiscal year ended September 30, 2013

The $9.7 million decrease in capital expenditures in fiscal 2014 compared to fiscal 2013 primarily reflects:

- A $63.9 million decrease in capital spending in our regulated pipeline segment primarily associated with the completion of the Line WX expansion project, partially offset by
- A $55.5 million increase in capital spending in our regulated distribution segment due to increased spending under our infrastructure replacement programs.

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 pipeline segment.

Cash flows from financing activities

We generated a net $73.6 million and $85.7 million in cash from financing activities for fiscal years 2014 and 2013. In fiscal 2012, we used a net $44.8 million of cash from financing activities. Our significant financing activities for the fiscal years ended September 30, 2014, 2013 and 2012 are summarized as follows:

2014

During the fiscal year ended September 30, 2014, our financing activities generated $73.6 million of cash compared with $85.7 million of cash generated in the prior year. The decrease is primarily due to timing between short-term debt borrowings and repayments during the current year partially offset by proceeds from the equity offering completed in February 2014 compared with proceeds generated from the issuance of long-term debt in fiscal 2013.

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 fiscal 2012. 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.

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The following table shows the number of shares issued for the fiscal years ended September 30, 2014, 2013 and 2012:

	For the Fiscal Year Ended September 30		
	2014	2013	2012
Shares issued:			
Direct Stock Purchase Plan	83,150	—	—
1998 Long-Term Incentive Plan	653,130	531,672	482,289
Outside Directors Stock-For-Fee Plan	1,735	2,088	2,375
February 2014 Offering	9,200,000	—	—
Total shares issued	9,938,015	533,760	484,664

The increase in the number of shares issued in fiscal 2014 compared with the number of shares issued in fiscal 2013 primarily reflects the equity offering completed in February 2014 as well as a higher number of performance-based awards issued in the current year as actual performance exceeded the target. At September 30, 2014, of the 8.7 million shares authorized for issuance from the LTIP, 845,139 million shares remained available. For the year ended September 30, 2014, we canceled and retired 190,134 shares attributable to federal income tax withholdings on equity awards which are not included in the table above.

The increased number of shares issued in fiscal 2013 compared with the number of shares issued in fiscal 2012 primarily reflects an increase in the amount of awards granted to a higher number of employees. For the year ended September 30, 2013, we canceled and retired 133,449 shares attributable to federal income tax withholdings on equity awards 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 $1.25 billion commercial paper program, which is collateralized by our $1.25 billion unsecured credit facility, as well as three additional committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. On August 22, 2014, we amended the $950 million credit facility to increase the committed loan amount from $950 million to $1.25 billion and extended the expiration date to August 22, 2019. The amended facility retains the $250 million accordion feature which allows for an increase in the total committed loan amount to $1.5 billion. As a result, we have approximately $1.3 billion of working capital funding. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

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. On February18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes. On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million 4.95% senior unsecured notes. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014. After giving effect to these issuances, $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

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.

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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-	A2	A-
Commercial paper	A-2	P-1	F-2

On January 30, 2014, Moody's upgraded our senior unsecured debt rating to A2 from Baa1 and our commercial paper rating to P-1 from P-2 with a rating outlook of stable. 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, 2014. Our debt covenants are described in Note 5 to the consolidated financial statements.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2014.

	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	$450,000	$1,260,000
Short-term debt[1]	196,695	196,695	—	—	—
Interest charges[2]	1,774,405	120,530	234,460	186,559	1,232,856
Capital lease obligations[3]	636	186	372	78	—
Operating leases[3]	155,689	16,673	32,351	31,045	75,620
Demand fees for contracted storage[4]	7,789	3,853	2,806	916	214
Demand fees for contracted transportation[5]	4,321	3,573	748	—	—
Financial instrument obligations[6]	21,856	1,730	20,126	—	—
Pension and postretirement benefit plan contributions[7]	412,977	33,558	64,776	123,459	191,184
Uncertain tax positions (including interest)[8]	12,629	—	12,629	—	—
Total contractual obligations	$5,046,997	$876,798	$618,268	$792,057	$2,759,874

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

(2) Interest charges were calculated using the stated rate for each debt issuance.
(3) See Note 9 to the consolidated financial statements.

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(4) Represents third party contractual demand fees for contracted storage in our nonregulated segment. Contractual demand fees for contracted storage for our regulated distribution segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.
(5) Represents third party contractual demand fees for transportation in our nonregulated segment.
(6) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2014. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.
(7) Represents expected contributions to our pension and postretirement benefit plans, which are discussed in Note 6 to the consolidated financial statements.
(8) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns.

Our regulated 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 also maintains a limited number of 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, 2014, we were committed to purchase 49.7 Bcf within one year and 69.8 Bcf within one to three years under indexed contracts.

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, 2014, AEH was committed to purchase 111.5 Bcf within one year, 19.8 Bcf within one to three years and 0.5 Bcf after three years under indexed contracts. AEH is committed to purchase 7.8 Bcf within one year under fixed price contracts with prices ranging from $1.96 to $4.49 per Mcf.

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 regulated distribution and nonregulated segments. In our regulated 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 regulated distribution segment's financial instruments for the fiscal year ended September 30, 2014 (in thousands):

Fair value of contracts at September 30, 2013	$109,648
Contracts realized/settled	5,221
Fair value of new contracts	1,516
Other changes in value	(102,101)
Fair value of contracts at September 30, 2014	$14,284

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The fair value of our regulated distribution segment's financial instruments at September 30, 2014, is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at September 30, 2014 Maturity in years Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$21,372	$(7,088)	$—	$—	$14,284
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$21,372	$(7,088)	$—	$—	$14,284

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, 2014 (in thousands):

Fair value of contracts at September 30, 2013	$(14,700)
Contracts realized/settled	9,052
Fair value of new contracts	—
Other changes in value	2,615
Fair value of contracts at September 30, 2014	(3,033)
Netting of cash collateral	25,758
Cash collateral and fair value of contracts at September 30, 2014	$22,725

The fair value of our nonregulated segment's financial instruments at September 30, 2014, is presented below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at September 30, 2014 Maturity in years Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(2,222)	$(810)	$(1)	$—	$(3,033)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(2,222)	$(810)	$(1)	$—	$(3,033)

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.We believe these programs are compliant with all current and future provisions that will be going into effect under The Patient Protection and Affordable Care Act and consistent with other programs in our industry. 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.

Over the last five fiscal years, we have experienced annual medical and prescription inflation of approximately six percent. For fiscal 2015, we anticipate the medical and prescription drug inflation rate will continue at approximately six percent, primarily due to a stable population and no significant changes anticipated for high cost claimant activity.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2014, our total net periodic pension and other benefits costs was $69.8 million, compared with $78.5 million and $69.2 million for the fiscal years ended September 30, 2013 and 2012. These costs relating to

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our regulated distribution operations are recoverable through our distribution rates. A portion of these costs is capitalized into our distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2014 costs were determined using a September 30, 2013 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2012, the measurement date for our fiscal 2013 net periodic cost. 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, our fiscal 2014 pension and postretirement medical costs were lower than in the prior year.

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 fiscal 2012.

Pension and Postretirement Plan Funding

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

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2014. Based on this valuation, we were required to contribute cash of $27.1 million, $32.7 million and $46.5 million to our pension plans during fiscal 2014, 2013 and 2012. The higher level of contributions experienced during fiscal 2013 and 2012 reflect lower discount rates. Each contribution increased the level of our plan assets to achieve a desirable PPA funding threshold.

We contributed $23.6 million, $26.6 million and $22.1 million to our postretirement benefits plans for the fiscal years ended September 30, 2014, 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 2015 and Beyond

As of September 30, 2014, interest and corporate bond rates were lower than the rates as of September 30, 2013. Therefore, we decreased the discount rate used to measure our fiscal 2015 net periodic cost from 4.95 percent to 4.43 percent. We maintained our expected return on plan assets at 7.25 percent in the determination of our fiscal 2015 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 2015 net periodic pension cost to decrease by approximately 10 percent.

Based upon current market conditions, the current funded position of the plans and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2015. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels. With respect to our postretirement medical plans, we anticipate contributing between $20 million and $25 million during fiscal 2015.

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 $2.4 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $1.2 million.

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

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase total amount of liabilities reported on our balance sheet in future periods.

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RECENT ACCOUNTING DEVELOPMENTS

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

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

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

We conduct risk management activities through both our regulated distribution and nonregulated segments. In our regulated 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

Regulated distribution segment

We purchase natural gas for our regulated distribution operations. Substantially all of the costs of gas purchased for regulated distribution operations are recovered from our customers through purchased gas cost adjustment mechanisms. Therefore, our regulated 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, 2014 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, 2014 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $2.8 million.

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

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $2.5 million during 2014.

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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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2014, 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, 2014, 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 6, 2014 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas

November 6, 2014

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ATMOS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	September 30 2014	2013
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$8,200,121	$7,446,272
Construction in progress	247,579	275,747
	8,447,700	7,722,019
Less accumulated depreciation and amortization	1,721,794	1,691,364
Net property, plant and equipment	6,725,906	6,030,655
Current assets		
Cash and cash equivalents	42,258	66,199
Accounts receivable, less allowance for doubtful accounts of $23,992 in 2014 and $20,624 in 2013	343,400	301,992
Gas stored underground	278,917	244,741
Other current assets	111,265	64,201
Total current assets	775,840	677,133
Goodwill	742,029	741,363
Deferred charges and other assets	350,929	485,117
	$8,594,704	$7,934,268
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2014 — 100,388,092 shares, 2013 — 90,640,211 shares	$502	$453
Additional paid-in capital	2,180,151	1,765,811
Accumulated other comprehensive income (loss)	(12,393)	38,878
Retained earnings	917,972	775,267
Shareholders' equity	3,086,232	2,580,409
Long-term debt	2,455,986	2,455,671
Total capitalization	5,542,218	5,036,080
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	311,604	241,611
Other current liabilities	402,351	368,891
Short-term debt	196,695	367,984
Total current liabilities	910,650	978,486
Deferred income taxes	1,286,616	1,164,053
Regulatory cost of removal obligation	445,387	359,299
Pension and postretirement liabilities	340,963	358,787
Deferred credits and other liabilities	68,870	37,563
	$8,594,704	$7,934,268

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2014	2013	2012
	(In thousands, except per share data)		
Operating revenues			
Regulated distribution segment	$3,061,546	$2,399,493	$2,145,330
Regulated pipeline segment	318,459	268,900	247,351
Nonregulated segment	2,067,292	1,587,914	1,348,982
Intersegment eliminations	(506,381)	(380,847)	(305,501)
	4,940,916	3,875,460	3,436,162
Purchased gas cost			
Regulated distribution segment	1,885,031	1,318,257	1,122,587
Regulated pipeline segment	—	—	—
Nonregulated segment	1,979,337	1,524,583	1,293,858
Intersegment eliminations	(505,878)	(379,430)	(304,022)
	3,358,490	2,463,410	2,112,423
Gross profit	1,582,426	1,412,050	1,323,739
Operating expenses			
Operation and maintenance	505,154	488,020	453,613
Depreciation and amortization	253,987	235,079	237,525
Taxes, other than income	211,936	187,072	181,073
Asset impairments	—	—	5,288
Total operating expenses	971,077	910,171	877,499
Operating income	611,349	501,879	446,240
Miscellaneous expense, net	(5,235)	(197)	(14,644)
Interest charges	129,295	128,385	141,174
Income from continuing operations before income taxes	476,819	373,297	290,422
Income tax expense	187,002	142,599	98,226
Income from continuing operations	289,817	230,698	192,196
Income from discontinued operations, net of tax ($0, $3,986 and $10,066)	—	7,202	18,172
Gain on sale of discontinued operations, net of tax ($0, $2,909 and $3,519)	—	5,294	6,349
Net income	$289,817	$243,194	$216,717
Basic earnings per share			
Income per share from continuing operations	$2.96	$2.54	$2.12
Income per share from discontinued operations	—	0.14	0.27
Net income per share — basic	$2.96	$2.68	$2.39
Diluted earnings per share			
Income per share from continuing operations	$2.96	$2.50	$2.10
Income per share from discontinued operations	—	0.14	0.27
Net income per share — diluted	$2.96	$2.64	$2.37
Weighted average shares outstanding:			
Basic	97,606	90,533	90,150
Diluted	97,608	91,711	91,172

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2014	2013	2012
	(In thousands)		
Net income	$289,817	$243,194	$216,717
Other comprehensive income (loss), net of tax			
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $1,199, $(186) and $1,881	2,214	(213)	3,103
Cash flow hedges:			
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(32,353), $47,236 and $(5,388)	(56,287)	82,179	(10,116)
Net unrealized gains on commodity cash flow hedges, net of tax of $1,791, $2,889 and $5,029	2,802	4,519	7,866
Total other comprehensive income (loss)	(51,271)	86,485	853
Total comprehensive income	$238,546	$329,679	$217,570

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, 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
Net income	—	—	—	—	289,817	289,817
Other comprehensive loss	—	—	—	(51,271)	—	(51,271)
Repurchase of equity awards	(190,134)	(1)	(8,716)	—	—	(8,717)
Cash dividends ($1.48 per share)	—	—	—	—	(146,248)	(146,248)
Common stock issued:						
Public offering	9,200,000	46	390,159	—	—	390,205
Direct stock purchase plan	83,150	1	4,066	—	—	4,067
1998 Long-term incentive plan	653,130	3	5,214	—	(864)	4,353
Employee stock-based compensation	—	—	23,536	—	—	23,536
Outside directors stock-for-fee plan	1,735	—	81	—	—	81
Balance, September 30, 2014	100,388,092	$502	$2,180,151	$ (12,393)	$917,972	$3,086,232

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2014	2013	2012
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$289,817	$243,194	$216,717
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	—	—	5,288
Gain on sale of discontinued operations	—	(8,203)	(9,868)
Depreciation and amortization:			
Charged to depreciation and amortization	253,987	236,928	246,093
Charged to other accounts	969	679	484
Deferred income taxes	189,952	141,336	104,319
Stock-based compensation	25,531	17,814	19,222
Debt financing costs	9,409	8,480	8,147
Other	(428)	(2,887)	(493)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(41,408)	(73,669)	32,578
(Increase) decrease in gas stored underground	(31,996)	31,979	28,417
(Increase) decrease in other current assets	(24,411)	15,644	20,989
(Increase) decrease in deferred charges and other assets	30,662	111,069	(50,055)
Increase (decrease) in accounts payable and accrued liabilities	55,041	31,912	(64,234)
Increase (decrease) in other current liabilities	2,413	(44,491)	7,889
Increase (decrease) in deferred credits and other liabilities	(19,552)	(96,658)	21,424
Net cash provided by operating activities	739,986	613,127	586,917
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(835,251)	(845,033)	(732,858)
Proceeds from the sale of discontinued operations	—	153,023	128,223
Other, net	(2,325)	(4,904)	(4,625)
Net cash used in investing activities	(837,576)	(696,914)	(609,260)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	(165,865)	(208,070)	354,141
Net proceeds from issuance of long-term debt	—	493,793	—
Net proceeds from equity offering	390,205	—	—
Settlement of Treasury lock agreements	—	(66,626)	—
Repayment of long-term debt	—	(131)	(257,034)
Cash dividends paid	(146,248)	(128,115)	(125,796)
Repurchase of common stock	—	—	(12,535)
Repurchase of equity awards	(8,717)	(5,150)	(5,219)
Issuance of common stock	4,274	46	1,606
Net cash provided by (used in) financing activities	73,649	85,747	(44,837)
Net increase (decrease) in cash and cash equivalents	(23,941)	1,960	(67,180)
Cash and cash equivalents at beginning of year	66,199	64,239	131,419
Cash and cash equivalents at end of year	$42,258	$66,199	$64,239
CASH PAID (RECEIVED) DURING THE PERIOD FOR:			
Interest	$156,606	$148,461	$150,606
Income taxes	$(610)	$10,008	$(432)

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 pipeline businesses as well as certain other nonregulated businesses. Through our regulated 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 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 distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our regulated 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.

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

Our regulated pipeline business, which is also subject to federal and state regulation, 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, regulated 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 regulated distribution and regulated pipeline operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs 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, 2014 and 2013 included the following:

	September 30	
	2014	2013
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$162,777	$187,977
Merger and integration costs, net	4,730	5,250
Deferred gas costs	20,069	15,152
Regulatory cost of removal asset	—	10,008
Rate case costs	3,757	6,329
Texas Rule 8.209[2]	26,948	30,364
APT annual adjustment mechanism	8,479	5,853
Recoverable loss on reacquired debt	18,877	21,435
Other	4,672	4,380
	$250,309	$286,748
Regulatory liabilities:		
Deferred gas costs	$35,063	$16,481
Deferred franchise fees	5,268	1,689
Regulatory cost of removal obligation	490,448	427,524
Other	14,980	7,887
	$545,759	$453,581

(1) Includes $18.8 million and $17.4 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.

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, 2014, 2013 and 2012, we recognized $0.5 million in amortization expense related to these costs.

Revenue recognition — Sales of natural gas to our regulated 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 regulated 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 regulated 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 pipeline 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, 2014, 2013 and 2012, we included unrealized gains (losses) on open contracts of $9.6 million, $9.0 million and $(8.0) 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 regulated 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 $1.5 million, $1.9 million and $2.6 million was capitalized in 2014, 2013 and 2012.

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, 3.3 percent and 3.6 percent for the fiscal years ended September 30, 2014, 2013 and 2012.

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.

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As of September 30, 2014 and 2013, we had asset retirement obligations of $10.5 million and $6.8 million. Additionally, we had $5.9 million and $3.3 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. See Note 14 for further details.

Goodwill — 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.

Marketable securities — As of September 30, 2014 and 2013, 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 regulated 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 regulated 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 regulated 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 purchased gas cost 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 purchased gas cost 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 purchased gas cost.

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, 2014 and 2013, the Company netted $25.8 million and $24.8 million of cash held in margin accounts into its current and noncurrent risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, primarily when we plan to issue new long-term debt or to refinance existing long-term debt. We manage this risk through the use of forward starting interest rate swaps, interest rate swaps, and prior to fiscal 2012, Treasury lock agreements, to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these financial instruments as cash flow hedges at the time the agreements are executed. Unrealized gains and losses associated with the instruments are recorded as a component of accumulated other comprehensive income (loss). When the instruments settle, the realized gain or loss is 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 is reported as a component of interest expense.

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

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, 2014, 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 seven to nine 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 use a corridor approach to amortize actuarial gains and losses. Under this approach, net gains or losses in excess of ten percent of the larger of the pension benefit obligation or the market-related value of the assets are amortized on a straight-line basis. The period of amortization is the average remaining service of active participants who are expected to receive benefits under the plan.

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.

Tax collections — We are allowed to recover from customers revenue-related taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues. However, we do collect and remit various other taxes on behalf of various governmental authorities, and we record these amounts in our consolidated balance sheets on a net basis. We do not collect income taxes from our customers on behalf of governmental authorities.

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 5 concerning the October 15, 2014 issuance of $500 million, 4.125% senior notes, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — Disclosure requirements for offsetting arrangements for financial instruments became effective for us beginning on October 1, 2013. We have presented these disclosures in Note 12. In connection with the adoption of this standard, prior-year risk management assets and liabilities have been reclassified to conform with the current-year presentation. The adoption of this standard and reclassification did not have an impact on our financial position, results of operations or cash flows.

In April 2014, the Financial Accounting Standards Board (FASB) issued updated guidance for discontinued operations that limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have a major effect on an entity’s operations and financial results and requires additional disclosures related to discontinued operations. This standard will become effective for us beginning on October 1, 2015. The adoption of this guidance is not expected to impact our financial position, results of operations or cash flows.

In May 2014, the FASB issued a comprehensive new revenue recognition standard that will supersede virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. The new standard will become effective for us beginning on October 1, 2017 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In August 2014, the FASB issued guidance that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity’s ability to continue as a going concern. If such conditions or events exist, disclosures are required that enable users of the financial statements to understand the nature of the conditions or events, management's evaluation of the circumstances and management's plans to mitigate the conditions or events that raise substantial doubt about the entity’s ability to continue as a going concern. We will be required to perform an annual assessment of our ability to continue as a going concern when this standard becomes effective for us on October 1, 2017; however, the adoption of this guidance is not expected to impact our financial position, results of operations or cash flows.

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3. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the regulated natural gas distribution and pipeline 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 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, regulated distribution companies, including certain divisions of Atmos Energy and third parties.

We operate the Company through the following three segments:

- The regulated distribution segment, includes our regulated distribution and related sales operations.
- The regulated pipeline 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 regulated distribution segment operations are geographically dispersed, they are reported as a single segment as each regulated 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.

Summarized income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$3,056,212	$92,166	$1,792,538	$—	$4,940,916
Intersegment revenues	5,334	226,293	274,754	(506,381)	—
	3,061,546	318,459	2,067,292	(506,381)	4,940,916
Purchased gas cost	1,885,031	—	1,979,337	(505,878)	3,358,490
Gross profit	1,176,515	318,459	87,955	(503)	1,582,426
Operating expenses					
Operation and maintenance	387,228	91,466	26,963	(503)	505,154
Depreciation and amortization	208,376	41,031	4,580	—	253,987
Taxes, other than income	196,343	13,143	2,450	—	211,936
Total operating expenses	791,947	145,640	33,993	(503)	971,077
Operating income	384,568	172,819	53,962	—	611,349
Miscellaneous income (expense)	(381)	(3,181)	2,216	(3,889)	(5,235)
Interest charges	94,918	36,280	1,986	(3,889)	129,295
Income before income taxes	289,269	133,358	54,192	—	476,819
Income tax expense	117,684	47,167	22,151	—	187,002
Net income	$171,585	$86,191	$32,041	$—	$289,817
Capital expenditures	$584,065	$249,347	$1,839	$—	$835,251

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

	Year Ended September 30, 2013				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,394,418	$89,011	$1,392,031	$—	$3,875,460
Intersegment revenues	5,075	179,889	195,883	(380,847)	—
	2,399,493	268,900	1,587,914	(380,847)	3,875,460
Purchased gas cost	1,318,257	—	1,524,583	(379,430)	2,463,410
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				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,144,376	$92,604	$1,199,182	$—	$3,436,162
Intersegment revenues	954	154,747	149,800	(305,501)	—
	2,145,330	247,351	1,348,982	(305,501)	3,436,162
Purchased gas cost	1,122,587	—	1,293,858	(304,022)	2,112,423
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

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

	2014	2013	2012
	(In thousands)		
Regulated distribution revenues:			
Gas sales revenues:			
Residential	$1,933,099	$1,512,495	$1,351,479
Commercial	876,042	661,930	587,651
Industrial	90,536	81,155	71,960
Public authority and other	64,779	60,557	54,334
Total gas sales revenues	2,964,456	2,316,137	2,065,424
Transportation revenues	64,049	55,938	53,924
Other gas revenues	27,707	22,343	25,028
Total regulated distribution revenues	3,056,212	2,394,418	2,144,376
Regulated pipeline revenues	92,166	89,011	92,604
Nonregulated revenues	1,792,538	1,392,031	1,199,182
Total operating revenues	$4,940,916	$3,875,460	$3,436,162

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

Balance sheet information at September 30, 2014 and 2013 by segment is presented in the following tables.

	September 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$5,202,761	$1,464,572	$58,573	$—	$6,725,906
Investment in subsidiaries	952,171	—	(2,096)	(950,075)	—
Current assets					
Cash and cash equivalents	33,303	—	8,955	—	42,258
Assets from risk management activities	23,102	—	22,725	—	45,827
Other current assets	490,408	14,009	526,161	(342,823)	687,755
Intercompany receivables	790,442	—	—	(790,442)	—
Total current assets	1,337,255	14,009	557,841	(1,133,265)	775,840
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	13,038	—	—	—	13,038
Deferred charges and other assets	309,965	21,826	6,100	—	337,891
	$8,390,006	$1,632,909	$655,129	$(2,083,340)	$8,594,704
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$3,086,232	$482,612	$469,559	$(952,171)	$3,086,232
Long-term debt	2,455,986	—	—	—	2,455,986
Total capitalization	5,542,218	482,612	469,559	(952,171)	5,542,218
Current liabilities					
Short-term debt	522,695	—	—	(326,000)	196,695
Liabilities from risk management activities	1,730	—	—	—	1,730
Other current liabilities	559,765	24,790	142,397	(14,727)	712,225
Intercompany payables	—	763,635	26,807	(790,442)	—
Total current liabilities	1,084,190	788,425	169,204	(1,131,169)	910,650
Deferred income taxes	913,260	361,688	11,668	—	1,286,616
Noncurrent liabilities from risk management activities	20,126	—	—	—	20,126
Regulatory cost of removal obligation	445,387	—	—	—	445,387
Pension and postretirement liabilities	340,963	—	—	—	340,963
Deferred credits and other liabilities	43,862	184	4,698	—	48,744
	$8,390,006	$1,632,909	$655,129	$(2,083,340)	$8,594,704

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	September 30, 2013				
	Regulated Distribution	Regulated Pipeline	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	—	10,129	—	11,966
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	524,217	(1,076,971)	677,133
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	8,849	—	375,763
	$7,800,418	$1,413,165	$626,696	$(1,906,011)	$7,934,268
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					
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	—	—	—	—	—
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	$626,696	$(1,906,011)	$7,934,268

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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:

	2014	2013	2012
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$289,817	$230,698	$192,196
Less: Income from continuing operations allocated to participating securities	711	775	793
Income from continuing operations available to common shareholders	$289,106	$229,923	$191,403
Basic weighted average shares outstanding	97,606	90,533	90,150
Income from continuing operations per share — Basic	$2.96	$2.54	$2.12
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$—	$12,496	$24,521
Less: Income from discontinued operations allocated to participating securities	—	42	101
Income from discontinued operations available to common shareholders	$—	$12,454	$24,420
Basic weighted average shares outstanding	97,606	90,533	90,150
Income from discontinued operations per share — Basic	$—	$0.14	$0.27
Net income per share — Basic	$2.96	$2.68	$2.39
Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$289,106	$229,923	$191,403
Effect of dilutive stock options and other shares	—	5	4
Income from continuing operations available to common shareholders	$289,106	$229,928	$191,407
Basic weighted average shares outstanding	97,606	90,533	90,150
Additional dilutive stock options and other shares	2	1,178	1,022
Diluted weighted average shares outstanding	97,608	91,711	91,172
Income from continuing operations per share — Diluted	$2.96	$2.50	$2.10
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$—	$12,454	$24,420
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$—	$12,454	$24,420
Basic weighted average shares outstanding	97,606	90,533	90,150
Additional dilutive stock options and other shares	2	1,178	1,022
Diluted weighted average shares outstanding	97,608	91,711	91,172
Income from discontinued operations per share — Diluted	$—	$0.14	$0.27
Net income per share — Diluted	$2.96	$2.64	$2.37

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 and 2012. As of September 30, 2014 there were no outstanding options.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement.

The offering was priced at $44.00 per share and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

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, 2014, a total of 387,991 shares had been repurchased for an aggregate value of $12.5 million, with no shares repurchased since the first quarter of fiscal 2012.

5. Debt

Long-term debt

Long-term debt at September 30, 2014 and 2013 consisted of the following:

	2014	2013
	(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	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
Total long-term debt	2,460,000	2,460,000
Less:		
Original issue discount on unsecured senior notes and debentures	4,014	4,329
Current maturities	—	—
	$2,455,986	$2,455,671

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million unsecured 4.95% senior notes. The effective rate of these notes is 4.086%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps discussed in Note 12. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014. Our $500 million 4.95% senior unsecured notes are presented as long-term debt at September 30, 2014 as we demonstrated the ability and intent to refinance through the issuance of new unsecured senior notes.

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 executed on September 27, 2012 to repay commercial paper borrowings used to redeem our $250 million Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. This facility bore interest at a LIBOR-based rate plus a company specific spread.

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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility, with a total availability from third-party lenders of approximately $1.3 billion of working capital funding. At September 30, 2014 and 2013, there was $196.7 million and $368.0 million outstanding under our commercial paper program with weighted average interest rates of

0.23% and 0.25%, 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 $1.3 billion of working capital funding. The first facility is a five-year unsecured facility that was amended on August 22, 2014 to 1) increase the borrowing capacity from $950 million to $1.25 billion with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 billion and 2) extend the expiration date from August 2018 to August 2019. 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 primarily as a backup liquidity facility for our commercial paper program. At September 30, 2014, there were no borrowings under this facility, but we had $196.7 million of commercial paper outstanding leaving $1,053.3 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility was renewed on April 1, 2014. At September 30, 2014, there were no borrowings outstanding under this facility.

The third facility which was renewed on September 30, 2014 for $10 million is a committed revolving credit facility, used primarily to issue letters of credit and bears interest at a LIBOR-based rate plus 1.5 percent. At September 30, 2014, 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, 2014, 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, 2014, our total-debt-to-total-capitalization ratio, as defined, was 48 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, 2014. There was $326.0 million outstanding under this facility at September 30, 2014.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, had two $25 million 364-day bilateral credit facilities that expired in December 2013. In December 2013, one of the $25 million 364-day uncommitted bilateral facilities was extended to December 2014. The other $25 million committed bilateral facility was replaced with a $15 million committed 364-day bilateral credit facility in December 2013. 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 $32.2 million at September 30, 2014.

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, 2014. There were no borrowings outstanding under this facility at September 30, 2014.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013, that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, which generated net proceeds of $390.2 million. After giving effect to this issuance and the aforementioned $500 million senior note issuance completed in October 2014, $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

Debt Covenants

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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, 2014. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2014 were as follows (in thousands):

2015	$500,000
2016	—
2017	250,000
2018	—
2019	450,000
Thereafter	1,260,000
	$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, 2014				
Unrecognized transition obligation	$—	$ —	$354	$354
Unrecognized prior service credit	(1,927)	—	(6,168)	(8,095)
Unrecognized actuarial loss	109,767	34,447	7,531	151,745
	$107,840	$ 34,447	$1,717	$144,004
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

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2014, 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.

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. In June 2014, active collectively bargained employees of Atmos Energy's Mississippi Division voted to decertify the union. As a result of this vote, effective January 1, 2015, active participants of the Union Plan will transfer to the Plan. Opening account balances will be established at the time of transfer equal to the present value of their respective accrued benefits under the Union Plan at December 31, 2014. In addition, effective January 1, 2015, current retirees in the Union Plan as well as those participants who have terminated and are vested in the Union Plan will transfer to the Plan with the same provisions that were in place at the time of their retirement or termination.

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 2014 and 2013 we contributed $27.1 million and $32.7 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 at September 30, 2014, the current funded position of the Plans and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2015. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

We make investment decisions and evaluate performance of the assets in the Master Trust 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, 2014 and 2013.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2014	2013

Domestic equities	35%-55%	51.9	%	46.5	%
International equities	10%-20%	15.3	%	16.1	%
Fixed income	10%-30%	9.7	%	14.9	%
Company stock	5%-15%	12.9	%	12.6	%
Other assets	5%-15%	10.2	%	9.9	%

At September 30, 2014 and 2013, the Plan held 1,169,700 shares of our common stock, which represented 12.9 percent and 12.6 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.7 million and $1.6 million during fiscal 2014 and 2013.

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, 2014 and 2013 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2013, 2012 and 2011. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2014	2013	2014	2013	2012
Discount rate	4.43 %	4.95 %	4.95 %	4.04 %	5.05 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	3.50 %	3.50 %
Expected return on plan assets	7.25 %	7.25 %	7.25 %	7.75 %	7.75 %

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2014 and 2013:

	2014	2013
	(In thousands)	
Accumulated benefit obligation	$466,182	$446,133
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$455,799	$480,031
Service cost	15,345	17,754
Interest cost	22,330	19,334
Actuarial (gain) loss	26,611	(29,822)
Benefits paid	(24,519)	(25,073)
Plan amendments	(1,972)	—
Divestitures	—	(6,425)
Benefit obligation at end of year	493,594	455,799
Change in plan assets:		
Fair value of plan assets at beginning of year	396,887	343,144
Actual return on plan assets	35,289	52,496
Employer contributions	27,110	32,745
Benefits paid	(24,519)	(25,073)
Divestitures	—	(6,425)
Fair value of plan assets at end of year	434,767	396,887
Reconciliation:		
Funded status	(58,827)	(58,912)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(58,827)	$(58,912)

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Net periodic pension cost for the Plans for fiscal 2014, 2013 and 2012 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2014	2013	2012
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$15,345	$17,754	$15,084
Interest cost	22,330	19,334	21,568
Expected return on assets	(23,601)	(22,955)	(21,474)
Amortization of prior service credit	(136)	(141)	(141)
Recognized actuarial loss	13,777	19,066	14,451
Net periodic pension cost	$27,715	$33,058	$29,488

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2014 and 2013. 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. In addition to the assets shown below, the Master Trust had net accounts receivable of $2.7 million and $0.4 million at September 30, 2014 and 2013 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2014			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Common stocks — domestic equities	$155,107	$—	$—	$155,107
Money market funds	—	11,226	—	11,226
Registered investment companies:				
Domestic funds	63,850	—	—	63,850
International funds	48,134	—	—	48,134
Common/collective trusts — domestic funds	—	61,208	—	61,208
Government securities:				
Mortgage-backed securities	—	12,520	—	12,520
U.S. treasuries	3,117	562	—	3,679
Corporate bonds	—	25,734	—	25,734
Limited partnerships	—	50,496	—	50,496
Real estate	—	—	155	155
Total investments at fair value	$270,208	$161,746	$155	$432,109

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	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

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 October 2, 2013, due to the retirement of one of our executives, we recognized a settlement loss of $4.5 million associated with our SEBP and made a $16.8 million benefit payment.

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.

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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, 2014 and 2013 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2013, 2012 and 2011. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2014	2013	2014	2013	2012
Discount rate	4.43%	4.95%	4.95%	4.04%[(1)]	5.05%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%

(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, 2014 and 2013:

	2014	2013
	(In thousands)	
Accumulated benefit obligation	$106,276	$109,817
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$117,080	$130,186
Service cost	3,607	3,039
Interest cost	4,966	4,755
Actuarial (gain) loss	9,468	(6,451)
Benefits paid	(5,085)	(4,375)
Settlements	(16,817)	(10,074)
Benefit obligation at end of year	113,219	117,080
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	21,902	14,449
Benefits paid	(5,085)	(4,375)
Settlements	(16,817)	(10,074)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(113,219)	(117,080)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(113,219)	$(117,080)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2014 and 2013, assets held in the rabbi trusts consisted of available-for-sale securities of $46.2 million and $44.5 million, which are included in our fair value disclosures in Note 14.

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Net periodic pension cost for the supplemental plans for fiscal 2014, 2013 and 2012 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2014	2013	2012
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$3,607	$3,039	$2,108
Interest cost	4,966	4,755	5,142
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	—	—
Recognized actuarial loss	1,948	2,918	2,118
Settlements	4,539	3,160	—
Net periodic pension cost	$15,060	$13,872	$9,368

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)	
2015	$33,592	$11,381
2016	32,811	4,617
2017	33,131	17,260
2018	33,501	14,772
2019	34,846	7,675
2020-2024	182,998	32,843

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 $20 million and $25 million to our postretirement benefits plan during fiscal 2015.

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, 2014 and 2013.

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Security Class	Actual Allocation September 30 2014	2013
Diversified investment funds	99.7 %	96.8 %
Cash and cash equivalents	0.3 %	3.2 %

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2014 and 2013 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2013, 2012 and 2011. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2014	2013	2014	2013	2012
Discount rate	4.43 %	4.95 %	4.95 %	4.04 %	5.05 %
Expected return on plan assets	4.60 %	4.60 %	4.60 %	4.70 %	5.00 %
Initial trend rate	7.50 %	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	2020	2020	2019	2018

The following table presents the postretirement plan’s benefit obligation and funded status as of September 30, 2014 and 2013:

	2014	2013
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$312,148	$308,315
Service cost	16,784	18,800
Interest cost	15,951	12,964
Plan participants’ contributions		