ATMOS ENERGY CORP
Form 10-K
November 06, 2015
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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, 2015
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number 1-10042
Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

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

Registrant's telephone number, including area code:
(972) 934-9227
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.45) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a smaller reporting company)
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ
The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant’s most recently completed second fiscal quarter, March 31, 2015, was $5,500,632,050.
As of October 30, 2015, the registrant had 101,506,645 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 3, 2016 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 Service, 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.

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.

Atmos Energy's vision is to be the safest provider of natural gas services. We intend to achieve this vision by:

- operating our business exceptionally well
- investing in our people and infrastructure
- enhancing our culture.

We believe the successful execution of this strategy has delivered excellent shareholder value. Over the last seven 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, 2015, we held 1,005 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. Historically, we have successfully renewed these franchises and believe that we will continue to 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	1,629,826
Kentucky/Mid-States	Kentucky	230	180,033
	Tennessee		141,141
	Virginia		23,567
Louisiana	Louisiana	300	356,579
West Texas	Amarillo, Lubbock, Midland	80	305,814
Mississippi	Mississippi	110	266,467
Colorado-Kansas	Colorado	170	115,048
	Kansas		132,837

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 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 2015 were Anadarko Energy Services Company, ConocoPhillips Company, Devon Gas Services, L.P., Enbridge Marketing (US) Inc., Hydrocarbon Exchange Corporation, Munich Re

Trading Ltd, Targa Gas Marketing LLC,

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Targa Pipeline Mid-Continent WestTex LLC, Tenaska Gas Storage, LLC, Texla Energy Management, Inc. and Atmos Energy Marketing, LLC and Trans Louisiana Gas Pipeline, Inc., wholly owned subsidiaries in our nonregulated segment.

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 2015 was on January 7, 2015, when sales to customers reached approximately 3.2 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 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 Permian Basin of West Texas. APT’s primary business is providing firm transportation and storage services for our Mid-Tex Division and other LDC customers. APT also provides interruptible transportation, storage and ancillary services for third parties including, industrial and electric generation customers as well as producers, marketers and other shippers.. The regulated pipeline segment represents approximately 30 percent of our consolidated operations.

Gross profit earned from transportation and storage services for our Atmos Pipeline - Texas Division is subject to traditional ratemaking governed by the RRC. Rates are updated through annual filings made under Texas’ Gas Reliability Infrastructure Program (GRIP) and Rider REV. GRIP allows us to include in our rates 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. Rider REV is an annual adjustment mechanism that adjusts the regulated rates for a portion of the variation in non-regulated annual revenues from a set base level.

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:

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- Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates.
- Infrastructure programs in place in four of our states that provide for an annual rate adjustment to rates.
- Implemented various rate mechanisms that allow us to recover over 90 percent of our capital expenditures are recovered within six months.
- Authorization in tariffs, statute, or commission rules that allows us to defer certain elements of our cost of service until they are included in rates, such as depreciation, ad valorem taxes and pension costs.
- WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our distribution gross margin.
- The ability to recover the gas cost portion of bad debts in five states.

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	04/08/2015	533,774(2)	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%
	Kansas-GSRS	02/01/2015	2,708	7.75%	N/A	9.10%
Kentucky/Mid-States	Kentucky	04/22/2014	252,738	7.71%	51/49	9.80%
	Kentucky-PRP	10/10/2014	35,382	7.71%	N/A	9.80%
	Tennessee	06/01/2015	247,958	7.73%	47/53	9.80%
	Virginia	09/09/2014	37,456	7.94%	46/54	9.00% - 10.00%
	Virginia-SAVE	10/01/2014	3,896	7.94%	N/A	9.00% - 10.00%
Louisiana	Trans La	04/01/2015	117,462	7.79%	47/53	9.80%
	LGS	07/01/2015	326,875	7.91%	46/54	9.80%
Mid-Tex Cities	Texas	06/01/2015	1,955,948(3)	8.43%	45/55	10.50%
Mid-Tex — Dallas	Texas	06/01/2015	1,935,160(3)	8.33%	46/54	10.10%
Mississippi	Mississippi	02/03/2015	322,610	8.26%	45/55	9.98%
	Mississippi - SGR	11/01/2014	8,960	9.37%	N/A	12.00%
West Texas(5)	Texas	03/15/2015	(4)	8.44%	(4)	10.50%
	Texas-GRIP	04/28/2015	379,303	8.57%	48/52	10.50%

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Division	Jurisdiction	Bad Debt Rider[6]	Formula Rate	Infrastructure Mechanism	Performance-Based Rate Program[7]	WNA Period
Atmos Pipeline — Texas	Texas	No	Yes	Yes	N/A	N/A
Colorado-Kansas	Colorado	No	No	Pending[8]	No	N/A
	Kansas	Yes	No	Yes	No	October-May
Kentucky/Mid-States	Kentucky	Yes	No	Yes	Yes	November-April
	Tennessee	Yes	Yes	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	Yes	Yes	November-April
West Texas[5]	Texas	Yes	Yes	Yes	No	October-May

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

(2) The APT rate base represents the incremental rate base from the 2011 APT filing.

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

(5) 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.

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

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

(8) The Company and intervenors have entered into a settlement agreement, approved on October 23, 2015, for implementation of an Infrastructure Mechanism effective January 1, 2016.

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 and pursue tariffs that reduce regulatory lag associated with investments. Further, potential changes in federal energy policy, federal safety regulations 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, 2015, 2014 and 2013 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 $114.5 million, $93.3 million and $98.1 million, became effective in fiscal 2015, 2014 and 2013, as summarized below:

Rate Action	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
	2015	2014	2013
	(In thousands)		
Annual formula rate mechanisms	$113,706	$71,749	$40,088
Rate case filings	711	21,819	56,700
Other ratemaking activity	78	(226)	1,322

	$114,495	$93,342	$98,110

Additionally, the following ratemaking efforts were initiated during fiscal 2015 but had not been completed as of September 30, 2015:

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Division	Rate Action	Jurisdiction	Operating Income Requested (In thousands)
Colorado-Kansas	Rate Case[1]	Colorado	$5,276
	Rate Case	Kansas	5,667
Kentucky/Mid-States	PRP[2]	Kentucky	3,786
	PRP [3]	Virginia	118
Mississippi	SRF	Mississippi	11,186
	SGR [4]	Mississippi	249
			$26,282

(1) A Stipulation and Settlement was signed on September 23, 2015. The settlement was approved on October 23, 2015 resulting in an operating income increase of $2.1 million and authorization to implement a long-term program to replace aging infrastructure in Colorado. The base rate change and infrastructure surcharge will go into effect on January 1, 2016.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Kentucky PRP was implemented on October 1, 2015.

(3) The PRP surcharge relates to a long-term program to replace aging infrastructure. The Virginia PRP was implemented on October 1, 2015.

(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 third year of the SGR program.

Our recent ratemaking activity is discussed in greater detail below.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate 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 mechanisms in our Louisiana, Mississippi, and Tennessee operations and in a portion of our Texas divisions. The formula 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 the stable rate filing (SRF) in the Mississippi Division, the rate stabilization clause (RSC) in the Louisiana Division, and Annual Rate Mechanism (ARM) in Tennessee.

Additionally, we have specific infrastructure programs in substantially all of our distribution divisions and our Atmos Pipeline - Texas Division, Colorado, Kansas, Kentucky, Mississippi, Texas and Virginia distribution operations have tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. These infrastructure programs are referred to as System Safety and Integrity Rider in Colorado (SSIR), Gas System Reliability Surcharge (GSRS) in Kansas, Pipeline Replacement Program (PRP) in Kentucky, System Integrity Rider in Mississippi (SIR), Gas Infrastructure Reliability Program (GRIP) and Steps to Advance Virginia Energy (SAVE). The following table summarizes our annual filing mechanisms with effective dates during the fiscal years ended September 30, 2015, 2014 and 2013:

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Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2015 Filings:				
Louisiana	LGS	12/2014	$1,321	07/01/2015
West Texas	Environs[1]	12/2014	697	06/12/2015
Mid-Tex	Environs[2]	12/2014	1,158	06/01/2015
Mid-Tex	Mid-Tex Cities	12/2014	16,801	06/01/2015
Mid-Tex	Dallas	09/2014	4,420	06/01/2015
West Texas	Cities[3]	12/2014	4,593	05/01/2015
Atmos Pipeline — Texas	Texas	12/2014	37,248	04/08/2015
Louisiana	Trans La	09/2014	(286)	04/01/2015
West Texas	West Texas Cities	09/2014	4,300	03/15/2015
Colorado-Kansas	Kansas	09/2014	301	02/01/2015
Mississippi	Mississippi-SRF	10/2015	4,441	02/01/2015
Mississippi	Mississippi-SGR	10/2015	782	11/01/2014
Kentucky/Mid-States	Kentucky [4]	09/2015	4,382	10/10/2014
Kentucky/Mid-States - Virginia	Virginia	09/2015	133	10/01/2014
Mid-Tex	Mid-Tex Cities[5]	12/2013	33,415	06/01/2014
Total 2015 Filings			$113,706	
2014 Filings:				
Louisiana	LGS	12/2013	$1,383	07/01/2014
West Texas	West Texas[1]	12/2013	858	06/17/2014
Mid-Tex	City of Dallas	09/2013	5,638	06/01/2014
Mid-Tex	Environs[2]	12/2013	881	05/22/2014
Atmos Pipeline — Texas	Texas	12/2013	45,589	05/06/2014
Louisiana	Trans La	09/2013	550	04/01/2014
Colorado-Kansas	Kansas	09/2013	882	02/01/2014
Mid-Tex	Mid-Tex Cities	12/2012	12,497	11/01/2013
Kentucky/Mid-States	Kentucky	09/2014	2,493	10/01/2013
Kentucky/Mid-States	Virginia	09/2014	210	10/01/2013
Mid-Tex	Environs[2]	12/2012	768	10/01/2013
Total 2014 Filings			$71,749	
2013 Filings:				
Louisiana	LGS	12/2012	$908	07/01/2013
Mid-Tex	City of Dallas	09/2012	1,800	06/01/2013
Atmos Pipeline — Texas	Texas	12/2012	26,730	05/07/2013
Louisiana	TransLa	09/2012	2,260	04/01/2013
Kentucky/Mid-States	Georgia[6]	09/2013	743	02/01/2013
Colorado-Kansas	Kansas	09/2012	601	01/09/2013
Mississippi	Mississippi	06/2012	3,441	11/01/2012
Kentucky/Mid-States	Georgia[6]	09/2011	1,079	10/01/2012
Kentucky/Mid-States	Kentucky[4]	09/2013	2,425	10/01/2012
Kentucky/Mid-States	Virginia	09/2013	101	10/01/2012
Total 2013 Filings			$40,088	

(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.

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(3) 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 cities of Amarillo, Channing, Dalhart and Lubbock in the West Texas Division only.

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

(5) On June 1, 2014 rates, subject to refund, were implemented. On June 1, 2015, concurrent with implementation of the 2015 RRM, final rates were implemented.

(6) 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.

Rate Case Filings

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

Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2015 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$711	06/01/2015
Total 2015 Rate Case Filings		$711	
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	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2015, 2014 and 2013:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2015 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$78	02/01/2015
Total 2015 Other Rate Activity			$78	
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	

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(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.

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, 2015, we had 4,753 employees, consisting of 4,642 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

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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 2015, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. Risk Factors.

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

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 Service, 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 intervenors. 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 in the context of traditional ratemaking. 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.”

However, in the last several years, a number of regulatory authorities in the states we serve have approved rate mechanisms that provide for annual adjustments to rates that allow us to recover the cost of investments made to replace existing infrastructure or reflect changes in our cost of service. These mechanisms work to effectively reduce the regulatory lag inherent in the ratemaking process. However, regulatory lag could significantly increase if the regulatory authorities modify or terminate these rate mechanisms. 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.

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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.

Over time, inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our 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.

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 minor 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.

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.

The regulated natural gas distribution and pipeline business is capital-intensive. We must make significant capital expenditures to renew or replace our facilities on a long-term basis to improve the safety and reliability of our facilities and to comply with the safety rules and regulations issued by the regulatory authorities responsible for the service areas we operate. In addition, we must continually build new capacity in our regulated distribution and regulated pipeline operations to serve the growing needs of the communities we serve. The magnitude of these expenditures may be affected by a number of factors, including new regulations, the general state of the economy and weather.

The liquidity required to fund our capital expenditures and other cash needs is provided from a variety of sources, including our cash flows from operations, borrowings under our short-term lending facilities, and, from time to time, funds raised from the public debt and equity capital markets. The cost and availability of borrowing funds from third party lenders or issuing equity is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit 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, should there be a material reduction in the amount of the recovery of these costs through our rates or should significant delays develop in the timing of the recovery of such costs, which could adversely affect our financial results.

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,

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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 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

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cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

Our 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, even though the Company has implemented policies, procedures and controls to prevent and detect these activities. We use our information technology 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 to the extent not fully covered by such insurance coverage.

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, 2015, in our regulated distribution segment, we owned an aggregate of 70,218 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 5,477 miles of gas transmission and gathering lines as well as 111 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, 2015:

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, 2015:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Regulated Distribution Segment			
	Colorado-Kansas Division	4,761,909	113,689
	Kentucky/Mid-States Division	11,181,603	268,739
	Louisiana Division	2,595,619	179,347
	Mid-Tex Division	3,250,000	175,000
	Mississippi Division	3,554,535	151,334
	West Texas Division	4,500,000	146,000
Total		29,843,666	1,034,109
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		39,544,535	1,352,553

(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, which is incorporated in this Item 3 by reference.

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 2015 and 2014 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 2015			Fiscal 2014		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$58.08	$47.35	$0.39	$47.06	$41.08	$0.37
March 31	58.81	52.02	0.39	48.01	44.19	0.37
June 30	56.41	51.28	0.39	53.40	46.94	0.37
September 30	58.18	51.48	0.39	52.68	47.01	0.37
			$1.56			$1.48

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 30, 2015 was 14,881. 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 2015 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor's 500 Stock Index and the cumulative total return of two different customized peer company groups, the New Comparison Company Index and the Old Comparison Company Index. The New Comparison Company Index includes ONE Gas, Inc., The Laclede Group, Inc. and TECO Energy, Inc. and excludes ONEOK, Inc., National Fuel Gas Company and Integrys Energy Group because the Board of Directors determined that these companies better fit the profile of the companies in our peer group, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2010 in our common stock, the S&P 500 Index and in the common stock of the companies in the New and Old Comparison Company Indexes, as well as a reinvestment of dividends paid on such investments throughout the period.

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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					
	9/30/2010	9/30/2011	9/30/2012	9/30/2013	9/30/2014	9/30/2015
Atmos Energy Corporation	100.00	115.72	133.03	164.05	189.51	237.91
S&P 500 Index	100.00	101.14	131.69	157.17	188.18	187.02
Old Comparison Company Index	100.00	117.66	142.22	167.00	201.17	193.52
New Comparison Company Index	100.00	116.24	134.26	155.06	179.39	204.94

The New Comparison Company Index reflects the cumulative total return of companies in our peer group, which is comprised of 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, Inc., CMS Energy Corporation, NiSource Inc., ONE Gas, Inc., Piedmont Natural Gas Company, Inc., Questar Corporation, TECO Energy, Inc., The Laclede Group, Inc., Vectren Corporation and WGL Holdings, Inc. The Old Comparison Company Index includes 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.

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The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2015.

	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	—	$ —	308,582
Total equity compensation plans approved by security holders	—	—	308,582
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	308,582

On September 28, 2011, the Board of Directors approved a program authorizing the repurchase of up to five million shares of common stock over a five-year period. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. We did not repurchase any shares during fiscal 2015 under the program, which is scheduled to end on September 30, 2016. At September 30, 2015, 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				
	2015	2014	2013	2012[1]	2011[1]
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$4,142,136	$4,940,916	$3,875,460	$3,436,162	$4,286,435
Gross profit	$1,680,017	$1,582,426	$1,412,050	$1,323,739	$1,300,820
Income from continuing operations	$315,075	$289,817	$230,698	$192,196	$189,588
Net income	$315,075	$289,817	$243,194	$216,717	$207,601
Diluted income per share from continuing operations	$3.09	$2.96	$2.50	$2.10	$2.07
Diluted net income per share	$3.09	$2.96	$2.64	$2.37	$2.27
Cash dividends declared per share	$1.56	$1.48	$1.40	$1.38	$1.36
Financial Condition					
Net property, plant and equipment[2]	$7,430,580	$6,725,906	$6,030,655	$5,475,604	$5,147,918
Total assets	$9,092,945	$8,594,704	$7,934,268	$7,495,675	$7,282,871
Capitalization:					
Shareholders' equity	$3,194,797	$3,086,232	$2,580,409	$2,359,243	$2,255,421
Long-term debt (excluding current maturities)	2,455,388	2,455,986	2,455,671	1,956,305	2,206,117
Total capitalization	$5,650,185	$5,542,218	$5,036,080	$4,315,548	$4,461,538

(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.

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

INTRODUCTION

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

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

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

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "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.

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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 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 or changes in the accounting for our various regulatory mechanisms could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income.	Decisions of regulatory authorities Issuance of new regulations or regulatory mechanisms Assessing the probability of the recoverability of deferred costs
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

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Pension and other postretirement plans	Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds. The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years. The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this methodology will delay the impact of current market fluctuations on the pension expense for the period. We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of	General economic and market conditions Assumed investment returns by asset class Assumed future salary increases Assumed discount rate Projected timing of future cash disbursements Health care cost experience trends Participant demographic information Actuarial mortality assumptions Impact of legislation Impact of regulation

	retirement is estimated based upon our annual review of our participant census information as of the measurement date.	
Contingencies	In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to uncollectible receivables, lawsuits, claims made by third parties or the action of various regulatory agencies. We recognize these contingencies in our consolidated financial statements when we determine, based on currently available facts and circumstances it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 10 to our consolidated financial statements.	Currently available facts Management's estimate of future resolution

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Financial instruments and hedging activities	We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses. These objectives are more fully described in Note 12 to the consolidated financial statements. We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. The recognition of the changes in fair value of these financial instruments recorded in the income statement is contingent upon whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Our accounting elections for financial instruments and hedging activities utilized are more fully described in Note 12 to the consolidated financial statements. The criteria used to determine if a financial instrument meets the definition of a derivative and qualifies for hedge accounting treatment are complex and require management to exercise professional judgment. Further, as more fully discussed below, significant changes in the fair value of these financial instruments could materially impact our financial position, results of operations or cash flows. Finally, changes in the effectiveness of the hedge relationship could impact the accounting treatment.	Designation of contracts under the hedge accounting rules Judgment in the application of accounting guidance Assessment of the probability that future hedged transactions will occur Changes in market conditions and the related impact on the fair value of the hedged item and the associated designated financial instrument Changes in the effectiveness of the hedge relationship
Fair Value Measurements	We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The assets and liabilities we recognize at fair value are subject to potentially significant volatility based on numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and timing of settlement. Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to	General economic and market conditions Volatility in underlying market conditions Maturity dates of financial instruments Creditworthiness of our counterparties Creditworthiness of Atmos Energy Impact of credit risk mitigation activities on the assessment of the creditworthiness of Atmos Energy and its counterparties

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

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

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Impairment assessments	We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstance indicate that such carrying values may not be recoverable, and at least annually for goodwill, as required by U.S. accounting standards. The evaluation of our goodwill balances and other long-lived assets or identifiable assets for which uncertainty exists regarding the recoverability of the carrying value of such assets involves the assessment of future cash flows and external market conditions and other subjective factors that could impact the estimation of future cash flows including, but not limited to the commodity prices, the amount and timing of future cash flows, future growth rates and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affect these estimates, which could result in an impairment charge.	General economic and market conditions Projected timing and amount of future discounted cash flows Judgment in the evaluation of relevant data

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation strives to operate its businesses safely and reliably while delivering superior shareholder value. In recent years we have implemented rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. In addition, recent pipeline safety rulemaking has impacted the level of operating and maintenance expense and capital spending in our regulated business, which we expect to continue. Accordingly, we have significantly increased investments in the safety and reliability of our natural gas distribution and transmission infrastructure. This increased level of investment and timely recovery of these investments through our various regulatory mechanisms has resulted in increased earnings and operating cash flow in recent years.

This trend continued during fiscal 2015. Net income increased 9 percent to $315.1 million, or $3.09 per diluted share. The year-over-year increase largely reflects positive rate outcomes, which more than offset weather that was 10 percent warmer than the prior year, particularly in our nonregulated segment. Additionally, operating cash flow increased $96.5 million to $836.5 million for the fiscal year ended September 30, 2015.

Capital expenditures for fiscal 2015 totaled $975.1 million. Approximately 80 percent was invested to improve the safety and reliability of our distribution and transportation systems, with a significant portion of this investment incurred under regulatory mechanisms that reduce lag to six months or less. Fiscal 2014 spending under these and other mechanisms enabled the Company to complete 17 regulatory filings during fiscal 2015 that should increase annual operating income from regulated operations by $114.5 million. We plan to continue to fund our growth through the use of operating cash flows and debt and equity securities, to maintain a balanced capital structure.

On July 1, 2015, Fitch Ratings (Fitch) upgraded our senior unsecured debt rating to A from A- with a ratings outlook of stable. Fitch cited its expectation of continued strong financial performance driven primarily by organic growth in our regulated distribution and regulated pipeline segments.

On October 29, 2015, S&P affirmed our senior unsecured debt rating as A- and issued a revised outlook from stable to positive, citing the potential for an upgraded rating in the future if we maintain our current level of financial performance as capital spending levels remain elevated.

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 7.7 percent for fiscal 2016.

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Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2015, 2014 and 2013.

	For the Fiscal Year Ended September 30		
	2015	2014	2013
	(In thousands, except per share data)		
Operating revenues	$4,142,136	$4,940,916	$3,875,460
Gross profit	1,680,017	1,582,426	1,412,050
Operating expenses	1,048,622	971,077	910,171
Operating income	631,395	611,349	501,879
Miscellaneous expense	(4,389)	(5,235)	(197)
Interest charges	116,241	129,295	128,385
Income from continuing operations before income taxes	510,765	476,819	373,297
Income tax expense	195,690	187,002	142,599
Income from continuing operations	315,075	289,817	230,698
Income from discontinued operations, net of tax	—	—	7,202
Gain on sale of discontinued operations, net of tax	—	—	5,294
Net income	$315,075	$289,817	$243,194
Diluted net income per share from continuing operations	$3.09	$2.96	$2.50
Diluted net income per share from discontinued operations	$—	$—	$0.14
Diluted net income per share	$3.09	$2.96	$2.64

Regulated operations contributed 95 percent, 89 percent and 95 percent to our consolidated net income from continuing operations for fiscal years 2015, 2014 and 2013. 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		
	2015	2014	2013
	(In thousands)		
Regulated distribution segment	$204,813	$171,585	$150,856
Regulated pipeline segment	94,662	86,191	68,260
Nonregulated segment	15,600	32,041	11,582
Net income from continuing operations	315,075	289,817	230,698
Net income from discontinued operations	—	—	12,496
Net income	$315,075	$289,817	$243,194

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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		
	2015	2014	2013
	(In thousands, except per share data)		
Regulated operations	$299,475	$257,776	$219,116
Nonregulated operations	15,600	32,041	11,582
Net income from continuing operations	315,075	289,817	230,698
Net income from discontinued operations	—	—	12,496
Net income	$315,075	$289,817	$243,194
Diluted EPS from continuing regulated operations	$2.93	$2.63	$2.38
Diluted EPS from nonregulated operations	0.16	0.33	0.12
Diluted EPS from continuing operations	3.09	2.96	2.50
Diluted EPS from discontinued operations	—	—	0.14
Consolidated diluted EPS	$3.09	$2.96	$2.64

We reported net income of $315.1 million, or $3.09 per diluted share for the year ended September 30, 2015, compared with net income of $289.8 million or $2.96 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year decreased net income by $1.5 million or $0.01 per diluted share compared with net gains recorded in the prior year of $5.8 million or $0.06 per diluted share.

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 fiscal 2013. Income from continuing operations in fiscal 2013 was $230.7 million, or $2.50 per diluted share. 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. Unrealized gains in our nonregulated operations during fiscal 2014 increased net income by $5.8 million or $0.06 per diluted share compared with net gains recorded in fiscal 2013 of $5.3 million, or $0.05 per diluted share.

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.

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 2015, we completed 16 regulatory proceedings in our regulated distribution segment, which should result in a $77.3 million increase in annual operating income.

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In April 2013, we completed the sale of our Georgia regulated distribution operations, representing approximately 64,000 customers.

Review of Financial and Operating Results

Financial and operational highlights for our regulated distribution segment for the fiscal years ended September 30, 2015, 2014 and 2013 are presented below.

	For the Fiscal Year Ended September 30				
	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	(In thousands, unless otherwise noted)				
Gross profit	$1,237,577	$1,176,515	$1,081,236	$61,062	$95,279
Operating expenses	817,428	791,947	738,143	25,481	53,804
Operating income	420,149	384,568	343,093	35,581	41,475
Miscellaneous income (expense)	(377)	(381)	2,535	4	(2,916)
Interest charges	84,132	94,918	98,296	(10,786)	(3,378)
Income from continuing operations before income taxes	335,640	289,269	247,332	46,371	41,937
Income tax expense	130,827	117,684	96,476	13,143	21,208
Income from continuing operations	204,813	171,585	150,856	33,228	20,729
Income from discontinued operations, net of tax	—	—	7,202	—	(7,202)
Gain on sale of discontinued operations, net of tax	—	—	5,649	—	(5,649)
Net Income	$204,813	$171,585	$163,707	$33,228	$7,878
Consolidated regulated distribution sales volumes from continuing operations — MMcf	293,350	317,320	269,162	(23,970)	48,158
Consolidated regulated distribution transportation volumes from continuing operations — MMcf	135,972	134,483	123,144	1,489	11,339
Consolidated regulated distribution throughput from continuing operations — MMcf	429,322	451,803	392,306	(22,481)	59,497
Consolidated regulated distribution throughput from discontinued operations — MMcf	—	—	4,731	—	(4,731)
Total consolidated regulated distribution throughput — MMcf	429,322	451,803	397,037	(22,481)	54,766
Consolidated regulated distribution average transportation revenue per Mcf	$0.50	$0.48	$0.46	$0.02	$0.02
Consolidated regulated distribution average cost of gas per Mcf sold	$5.20	$5.94	$4.91	$(0.74)	$1.03

Fiscal year ended September 30, 2015 compared with fiscal year ended September 30, 2014

Income from continuing operations for our regulated distribution segment increased 19 percent, primarily due to a $61.1 million increase in gross profit, partially offset by a $25.5 million increase in operating expenses. The year-to-date increase in gross profit primarily reflects:

- a $70.6 million net increase in rate adjustments, primarily in our Mid-Tex, West Texas, Kentucky/Mid-States and Colorado-Kansas Divisions.
- a $4.5 million increase in transportation revenue. Transportation volumes increased one percent due to increased economic activity experienced in our Kentucky/Mid-States Division and increased consumption in our West Texas Division due to colder than normal weather.
-

a $10.5 million decrease in consumption associated with an eight percent decrease in sales volumes. Current period weather was ten percent warmer compared to the prior-year period, before adjusting for weather normalization mechanisms.

- a $2.5 million decrease in revenue-related taxes primarily in our Mid-Tex Division.

The increase in operating expenses, which include operation and maintenance expense, bad debt expense, depreciation and amortization expense and taxes, other than income, was primarily due to increased depreciation expense associated with increased capital investments and increased ad valorem and franchise taxes.

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Interest charges decreased by $10.8 million, primarily due to replacing our $500 million unsecured 4.95% senior notes with $500 million of 4.125% 30-year unsecured senior notes on October 15, 2014 and higher interest expense deferrals under our infrastructure mechanisms.

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, bad debt expense, 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.
- 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.

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, 2015, 2014 and 2013. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	(In thousands)				
Mid-Tex	$197,559	$187,265	$158,900	$10,294	$28,365
Kentucky/Mid-States	59,233	55,968	46,164	3,265	9,804
Louisiana	51,001	56,648	52,125	(5,647)	4,523
West Texas	37,180	29,250	28,085	7,930	1,165
Mississippi	34,333	28,473	29,112	5,860	(639)
Colorado-Kansas	28,720	28,077	25,478	643	2,599
Other	12,123	(1,113)	3,229	13,236	(4,342)
Total	$420,149	$384,568	$343,093	$35,581	$41,475

Regulated Pipeline Segment

Our regulated pipeline segment consists of the pipeline and storage operations of the 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 Permian Basin of West Texas. APT's primary business is providing firm transportation and storage services for our Mid-Tex Division and other LDC customers. APT also provides interruptible transportation, storage and ancillary services for third parties including, industrial and electric generation customers as well as producers, marketers and other shippers..

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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 impact the market value for transportation services between those geographic areas.

The results of the 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, 2015, 2014 and 2013 are presented below.

	For the Fiscal Year Ended September 30				
	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$264,059	$227,230	$179,628	$36,829	$47,602
Third-party transportation	94,893	76,109	66,939	18,784	9,170
Storage and park and lend services	3,575	5,344	5,985	(1,769)	(641)
Other	7,585	9,776	16,348	(2,191)	(6,572)
Gross profit	370,112	318,459	268,900	51,653	49,559
Operating expenses	188,845	145,640	129,047	43,205	16,593
Operating income	181,267	172,819	139,853	8,448	32,966
Miscellaneous expense	(1,243)	(3,181)	(2,285)	1,938	(896)
Interest charges	33,151	36,280	30,678	(3,129)	5,602
Income before income taxes	146,873	133,358	106,890	13,515	26,468
Income tax expense	52,211	47,167	38,630	5,044	8,537
Net income	$94,662	$86,191	$68,260	$8,471	$17,931
Gross pipeline transportation volumes — MMcf	738,532	714,464	649,740	24,068	64,724
Consolidated pipeline transportation volumes — MMcf	528,068	493,360	467,178	34,708	26,182

Fiscal year ended September 30, 2015 compared with fiscal year ended September 30, 2014

Net income for our regulated pipeline segment increased 10 percent, primarily due to a $51.7 million increase in gross profit, partially offset by a $43.2 million increase in operating expenses. The increase in gross profit primarily reflects a $47.0 million increase in rates from the approved 2014 and 2015 Gas Reliability Infrastructure Program (GRIP) filings. Additionally, gross profit reflects increased pipeline demand fees and through-system transportation volumes and rates that were offset by lower storage and other fees and the absence of a $1.8 million increase recorded in the prior-year associated with an annual adjustment mechanism.

Operating expenses increased $43.2 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments, along with the absence of a $6.7 million refund received in the prior year as a result of the completion of a state use tax audit.

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

Net income for our regulated pipeline segment increased 26 percent in fiscal 2014 compared to fiscal 2013, 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 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

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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.

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. 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, 2015, 2014 and 2013 are presented below.

	For the Fiscal Year Ended September 30				
	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$48,930	$39,529	$39,839	$9,401	$(310)
Storage and transportation services	13,575	14,696	14,641	(1,121)	55
Other	12,755	24,170	(103)	(11,415)	24,273
Total realized margins	75,260	78,395	54,377	(3,135)	24,018
Unrealized margins	(2,400)	9,560	8,954	(11,960)	606
Gross profit	72,860	87,955	63,331	(15,095)	24,624
Operating expenses	42,881	33,993	44,404	8,888	(10,411)
Operating income	29,979	53,962	18,927	(23,983)	35,035
Miscellaneous income (expense)	(760)	2,216	2,316	(2,976)	(100)
Interest charges	967	1,986	2,168	(1,019)	(182)
Income from continuing operations before income taxes	28,252	54,192	19,075	(25,940)	35,117
Income tax expense	12,652	22,151	7,493	(9,499)	14,658
Income from continuing operations	15,600	32,041	11,582	(16,441)	20,459
Loss on sale of discontinued operations, net of tax	—	—	(355)	—	355
Net income	$15,600	$32,041	$11,227	$(16,441)	$20,814
Gross nonregulated delivered gas sales volumes — MMcf	410,044	439,014	396,561	(28,970)	42,453
Consolidated nonregulated delivered gas sales volumes — MMcf	351,427	377,441	343,669	(26,014)	33,772
Net physical position (Bcf)	14.6	9.3	12.0	5.3	(2.7)

Fiscal year ended September 30, 2015 compared with fiscal year ended September 30, 2014

Net income for our nonregulated segment decreased 51 percent from the prior year due to lower gross profit and higher operating expenses.

The $15.1 million period-over-period decrease in gross profit was primarily due to a $12.0 million decrease in unrealized margins combined with a $3.1 million decrease in realized margins. The decrease in realized margins reflects:

- An $11.4 million decrease in other realized margins primarily due to lower natural gas price volatility. In the prior-year period, strong market demand caused by significantly colder-than-normal weather resulted in increased market volatility. These market conditions created the opportunity to accelerate physical withdrawals that had been planned for future periods into the fiscal 2014 second quarter to capture incremental gross profit margin. Market conditions in the current-year period were less volatile than the prior-year period, which provided fewer opportunities to capture incremental gross profit.
- A $9.4 million increase in gas delivery and related services margins, primarily due to an increase in per-unit margins from 9 cents to 12 cents per Mcf, partially offset by a seven percent decrease in consolidated sales volumes. AEH elected not to renew excess transportation capacity in certain markets in late fiscal 2014 and early 2015. As a result, AEH has experienced fewer deliveries to low-margin marketing and power generation customers, which is the primary driver for the decrease in consolidated sales volumes and higher per-unit margins.

Operating expenses increased $8.9 million, primarily due to higher legal expenses as a result of the favorable settlement in the prior year of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter.

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

Net income for our nonregulated segment increased 185 percent in fiscal year 2014 compared to the year ended September 30, 2013 due to higher gross profit and decreased operating expenses.

The 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 favorable resolution of the Tennessee Business License Tax matter in fiscal 2014.

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 45 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, 2015 and 2014:

	September 30				
	2015			2014	
	(In thousands, except percentages)				
Short-term debt	$457,927	7.5	%	$196,695	3.4	%
Long-term debt	2,455,388	40.2	%	2,455,986	42.8	%
Shareholders’ equity	3,194,797	52.3	%	3,086,232	53.8	%
Total capitalization, including short-term debt	$6,108,112	100.0	%	$5,738,913	100.0	%

Total debt as a percentage of total capitalization, including short-term debt, was 47.7 percent and 46.2 percent at September 30, 2015 and 2014.

As we continue to invest in the safety and reliability of our distribution and transportation system, we expect our capital spending will increase in future periods. We intend to fund this level of investment through available operating cash flows, the issuance of long-term debt securities and equity. We believe the liquidity provided by these sources combined with our committed credit facilities will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2016 and beyond.

On September 25, 2015, we terminated our existing $1.25 billion credit facility and entered into a new five year $1.25 billion credit facility with substantially the same terms. The new facility also 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 and 2015, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated fiscal 2019 issuances at 3.782%. In fiscal 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated fiscal 2017 issuances at 3.367%.

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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, 2015, 2014 and 2013 are presented below.

	For the Fiscal Year Ended September 30				
	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$836,519	$739,986	$613,127	$96,533	$126,859
Investing activities	(974,755)	(837,576)	(696,914)	(137,179)	(140,662)
Financing activities	124,631	73,649	85,747	50,982	(12,098)
Change in cash and cash equivalents	(13,605)	(23,941)	1,960	10,336	(25,901)
Cash and cash equivalents at beginning of period	42,258	66,199	64,239	(23,941)	1,960
Cash and cash equivalents at end of period	$28,653	$42,258	$66,199	$(13,605)	$(23,941)

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, 2015 compared with fiscal year ended September 30, 2014

For the fiscal year ended September 30, 2015, we generated operating cash flow of $836.5 million from operating activities compared with $740.0 million in the prior year. The year-over-year increase primarily reflects successful rate case outcomes in the prior year, the timing of gas cost recoveries under our purchased gas cost mechanisms and lower gas prices during the current-year storage injection season.

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 fiscal 2013. 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.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund our ongoing construction program, which 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 and, more recently, expand our intrastate pipeline network. Over the last three 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 target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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.

For the fiscal year ended September 30, 2015, we incurred $975.1 million for capital expenditures compared with $835.3 million for the fiscal year ended September 30, 2014 and $845.0 million for the fiscal year ended September 30, 2013.

Fiscal Year ended September 30, 2015 compared with fiscal year ended September 30, 2014

The $139.8 million increase in capital expenditures in fiscal 2015 compared to fiscal 2014 primarily reflects:

- A $96.9 million increase in capital spending in our regulated distribution segment, which primarily reflects a planned increase in safety and reliability investment in fiscal 2015.
-

A $43.4 million increase in capital spending in our regulated pipeline segment, primarily related to the enhancement and fortification of two storage fields to ensure the reliability of gas service to our Mid-Tex Division.

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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.

Cash flows from financing activities

We generated a net $124.6 million, $73.6 million and $85.7 million in cash from financing activities for fiscal years 2015, 2014 and 2013. Our significant financing activities for the fiscal years ended September 30, 2015, 2014 and 2013 are summarized as follows:

2015

During the fiscal year ended September 30, 2015, our financing activities generated $124.6 million of cash compared with $73.6 million of cash generated in the prior year. The increase is primarily due to timing between short-term debt borrowings and repayments during the current year, proceeds from the issuance of $500 million unsecured 4.125% senior notes in October 2014 and the settlement of the associated forward starting interest rate swaps. Partially offsetting these increases were the repayment of $500 million 4.95% senior unsecured notes at maturity on October 15, 2014, compared with short-term debt borrowings and repayments in the prior year and proceeds generated from the equity offering completed in February 2014.

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 fiscal 2014 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. Fiscal year 2013 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.

The following table shows the number of shares issued for the fiscal years ended September 30, 2015, 2014 and 2013:

	For the Fiscal Year Ended September 30		
	2015	2014	2013
Shares issued:			
Direct Stock Purchase Plan	176,391	83,150	—
Retirement Savings Plan	398,047	—	—
1998 Long-Term Incentive Plan	664,752	653,130	531,672
Outside Directors Stock-For-Fee Plan	—	1,735	2,088
February 2014 Offering	—	9,200,000	—
Total shares issued	1,239,190	9,938,015	533,760

The decrease in the number of shares issued in fiscal 2015 compared with the number of shares issued in fiscal 2014 primarily reflects the equity offering completed in February 2014, partially offset by the fact that we have begun issuing shares for use by the Direct Stock Purchase Plan and the Retirement Savings Plan and Trust rather than using shares purchased in the open market. At September 30, 2015, of the 8.7 million shares authorized for issuance from the LTIP, 308,582 shares remained available. For the year ended September 30, 2015, we canceled and retired 148,464 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 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

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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 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.

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 that provide approximately $1.3 billion of working capital funding. The $1.25 billion unsecured credit facility has a $250 million accordion feature which allows for an increase in the total committed loan amount to $1.5 billion. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission that permits us to issue a total of $1.75 billion in common stock and/or debt securities. The shelf registration statement is effective until March 28, 2016. As of September 30, 2015, $845 million was available for issuance.

Credit Ratings

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

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

	S&P	Moody's	Fitch
Unsecured senior long-term debt	A-	A2	A
Commercial paper	A-2	P-1	F-2

On July 1, 2015, Fitch upgraded our senior unsecured debt rating to A from A- with a ratings outlook of stable, citing Fitch's expectation of continued strong financial performance, which has been driven primarily by organic growth in our regulated distribution and regulated pipeline segments.

On October 29, 2015, S&P affirmed our senior unsecured debt rating as A- and issued a revised outlook from stable to positive, citing the potential for an upgraded rating in the future if we maintain our current level of financial performance as capital spending levels remain elevated.

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.

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Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2015. 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, 2015.

	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	$—	$250,000	$450,000	$1,760,000
Short-term debt[1]	457,927	457,927	—	—	—
Interest charges[2]	2,252,802	140,192	259,835	189,559	1,663,216
Operating leases[3]	140,713	16,475	33,129	29,458	61,651
Demand fees for contracted storage[4]	8,188	3,853	3,977	286	72
Demand fees for contracted transportation[5]	7,068	3,990	1,511	538	1,029
Financial instrument obligations[6]	120,107	9,568	110,539	—	—
Pension and postretirement benefit plan contributions[7]	325,606	37,355	50,138	60,238	177,875
Uncertain tax positions[8]	17,069	—	17,069	—	—
Total contractual obligations	$5,789,480	$669,360	$726,198	$730,079	$3,663,843

(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.

(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 and interest rate financial instruments that were valued as of September 30, 2015. 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, 2015, we were committed to purchase 36.6 Bcf within one year and 26.8 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, 2015, AEH was committed to purchase 101.9 Bcf within one year, 16.0 Bcf within one to three years and 0.5 Bcf after three years under indexed contracts. AEH is committed to purchase 3.0 Bcf within one year under fixed price contracts with prices ranging from $2.32 to $3.23 per Mcf.

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Risk Management Activities

As discussed above in our Critical Accounting Policies, we use financial instruments to mitigate commodity price risk and, periodically, to manage interest rate risk. We conduct risk management activities through our 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, 2015 (in thousands):

Fair value of contracts at September 30, 2014	$14,284
Contracts realized/settled	(33,892)
Fair value of new contracts	607
Other changes in value	(100,360)
Fair value of contracts at September 30, 2015	$(119,361)

The fair value of our regulated distribution segment's financial instruments at September 30, 2015, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2015				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(9,190)	$(110,171)	$—	$—	$(119,361)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(9,190)	$(110,171)	$—	$—	$(119,361)

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, 2015 (in thousands):

Fair value of contracts at September 30, 2014	$(3,033)
Contracts realized/settled	21,401
Fair value of new contracts	—
Other changes in value	(52,988)
Fair value of contracts at September 30, 2015	(34,620)
Netting of cash collateral	43,474
Cash collateral and fair value of contracts at September 30, 2015	$8,854

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The fair value of our nonregulated segment's financial instruments at September 30, 2015, is presented below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at September 30, 2015 Maturity in years Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(24,928)	$(8,925)	$(767)	$—	$(34,620)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(24,928)	$(8,925)	$(767)	$—	$(34,620)

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 five percent. For fiscal 2016, we anticipate the medical and prescription drug inflation rate will continue at approximately five percent, primarily due to the inflation of health care costs.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2015, our total net periodic pension and other benefits costs was $58.9 million, compared with $69.8 million and $78.5 million for the fiscal years ended September 30, 2014 and 2013. These costs relating to 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 2015 costs were determined using a September 30, 2014 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, 2013, the measurement date for our fiscal 2014 net periodic cost. 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 these and other assumptions, our fiscal 2015 pension and postretirement medical costs were lower than in the prior year.

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 of the net impact of these and other assumptions, our fiscal 2014 pension and postretirement medical costs were lower than in the prior year.

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, 2015. Based on this valuation, we contributed cash of $38.0 million, $27.1 million and $32.7 million to our pension plans during fiscal 2015, 2014 and 2013. Each contribution increased the level of our plan assets to achieve a desirable PPA funding threshold.

We contributed $20.0 million, $23.6 million and $26.6 million to our postretirement benefits plans for the fiscal years ended September 30, 2015, 2014 and 2013. 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 2016 and Beyond

As of September 30, 2015, interest and corporate bond rates were higher than the rates as of September 30, 2014. Therefore, we increased the discount rate used to measure our fiscal 2016 net periodic cost from 4.43 percent to 4.55 percent. We lowered expected return on plan assets from 7.25 percent to 7.00 percent in the determination of our fiscal 2016 net periodic pension cost based upon expected market returns for our targeted asset allocation. 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. On October 8, 2015, the Society of Actuaries issued an additional report related to mortality tables and the mortality improvement scale. As of September 30, 2015, we updated our assumed mortality rates to incorporate both new sets of mortality tables. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2016 net periodic pension cost to decrease by approximately 20 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 2016. 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 $30 million and $40 million during fiscal 2016.

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 $2.7 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.

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.

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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, 2015 of 1.0 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.3 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2015 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $4.4 million.

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

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $2.7 million during 2015.

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ITEM 8. Financial Statements and Supplementary Data.

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Consolidated balance sheets at September 30, 2015 and 2014	45
Consolidated statements of income for the years ended September 30, 2015, 2014 and 2013	46
Consolidated statements of comprehensive income for the years ended September 30, 2015, 2014 and 2013	47
Consolidated statements of shareholders' equity for the years ended September 30, 2015, 2014 and 2013	48
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Selected Quarterly Financial Data (Unaudited)	96
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All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and accompanying notes thereto.

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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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2015, 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, 2015, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 6, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
November 6, 2015

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ATMOS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	September 30 2015	2014
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$8,959,702	$8,200,121
Construction in progress	280,398	247,579
	9,240,100	8,447,700
Less accumulated depreciation and amortization	1,809,520	1,721,794
Net property, plant and equipment	7,430,580	6,725,906
Current assets		
Cash and cash equivalents	28,653	42,258
Accounts receivable, less allowance for doubtful accounts of $15,283 in 2015 and $23,992 in 2014	295,160	343,400
Gas stored underground	236,603	278,917
Other current assets	70,569	111,265
Total current assets	630,985	775,840
Goodwill	742,702	742,029
Deferred charges and other assets	288,678	350,929
	$9,092,945	$8,594,704
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2015 — 101,478,818 shares, 2014 — 100,388,092 shares	$507	$502
Additional paid-in capital	2,230,591	2,180,151
Accumulated other comprehensive loss	(109,330)	(12,393)
Retained earnings	1,073,029	917,972
Shareholders' equity	3,194,797	3,086,232
Long-term debt	2,455,388	2,455,986
Total capitalization	5,650,185	5,542,218
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	238,942	308,086
Other current liabilities	457,954	405,869
Short-term debt	457,927	196,695
Total current liabilities	1,154,823	910,650
Deferred income taxes	1,411,315	1,286,616
Regulatory cost of removal obligation	427,553	445,387
Pension and postretirement liabilities	287,373	340,963
Deferred credits and other liabilities	161,696	68,870
	$9,092,945	$8,594,704

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2015	2014	2013
	(In thousands, except per share data)		
Operating revenues			
Regulated distribution segment	$2,763,835	$3,061,546	$2,399,493
Regulated pipeline segment	370,112	318,459	268,900
Nonregulated segment	1,472,209	2,067,292	1,587,914
Intersegment eliminations	(464,020)	(506,381)	(380,847)
	4,142,136	4,940,916	3,875,460
Purchased gas cost			
Regulated distribution segment	1,526,258	1,885,031	1,318,257
Regulated pipeline segment	—	—	—
Nonregulated segment	1,399,349	1,979,337	1,524,583
Intersegment eliminations	(463,488)	(505,878)	(379,430)
	2,462,119	3,358,490	2,463,410
Gross profit	1,680,017	1,582,426	1,412,050
Operating expenses			
Operation and maintenance	541,868	505,154	488,020
Depreciation and amortization	274,796	253,987	235,079
Taxes, other than income	231,958	211,936	187,072
Total operating expenses	1,048,622	971,077	910,171
Operating income	631,395	611,349	501,879
Miscellaneous expense, net	(4,389)	(5,235)	(197)
Interest charges	116,241	129,295	128,385
Income from continuing operations before income taxes	510,765	476,819	373,297
Income tax expense	195,690	187,002	142,599
Income from continuing operations	315,075	289,817	230,698
Income from discontinued operations, net of tax ($0, $0 and $3,986)	—	—	7,202
Gain on sale of discontinued operations, net of tax ($0, $0 and $2,909)	—	—	5,294
Net income	$315,075	$289,817	$243,194
Basic earnings per share			
Income per share from continuing operations	$3.09	$2.96	$2.54
Income per share from discontinued operations	—	—	0.14
Net income per share — basic	$3.09	$2.96	$2.68
Diluted earnings per share			
Income per share from continuing operations	$3.09	$2.96	$2.50
Income per share from discontinued operations	—	—	0.14
Net income per share — diluted	$3.09	$2.96	$2.64
Weighted average shares outstanding:			
Basic	101,892	97,606	90,533
Diluted	101,892	97,608	91,711

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2015	2014	2013
	(In thousands)		
Net income	$315,075	$289,817	$243,194
Other comprehensive income (loss), net of tax			
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(1,559), $1,199 and $(186)	(2,713)	2,214	(213)
Cash flow hedges:			
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(40,501), $(32,353) and $47,236	(70,461)	(56,287)	82,179
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $(15,193), $1,791 and $2,889	(23,763)	2,802	4,519
Total other comprehensive income (loss)	(96,937)	(51,271)	86,485
Total comprehensive income	$218,138	$238,546	$329,679

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock					
	Number of Shares	Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	(In thousands, except share and per share data)					
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
Net income	—	—	—	—	315,075	315,075
Other comprehensive loss	—	—	—	(96,937)	—	(96,937)
Repurchase of equity awards	(148,464)	(1)	(7,984)	—	—	(7,985)
Cash dividends ($1.56 per share)	—	—	—	—	(160,018)	(160,018)
Common stock issued:						
Direct stock purchase plan	176,391	1	10,625	—	—	10,626
Retirement savings plan	398,047	2	20,324	—	—	20,326
1998 Long-term incentive plan	664,752	3	2,263	—	—	2,266
Employee stock-based compensation	—	—	25,212	—	—	25,212
Balance, September 30, 2015	101,478,818	$507	$2,230,591	$ (109,330)	$1,073,029	$3,194,797

See accompanying notes to consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2015	2014	2013
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$315,075	$289,817	$243,194
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of discontinued operations	—	—	(8,203)
Depreciation and amortization:			
Charged to depreciation and amortization	274,796	253,987	236,928
Charged to other accounts	1,209	969	679
Deferred income taxes	192,886	189,952	141,336
Stock-based compensation	27,491	25,531	17,814
Debt financing costs	5,922	9,409	8,480
Other	(850)	(428)	(2,887)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	48,240	(41,408)	(73,669)
(Increase) decrease in gas stored underground	33,234	(31,996)	31,979
(Increase) decrease in other current assets	(11,951)	(24,411)	15,644
Decrease in deferred charges and other assets	58,256	30,662	111,069
Increase (decrease) in accounts payable and accrued liabilities	(52,660)	55,041	31,912
Increase (decrease) in other current liabilities	896	2,413	(44,491)
Decrease in deferred credits and other liabilities	(56,025)	(19,552)	(96,658)
Net cash provided by operating activities	836,519	739,986	613,127
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(975,132)	(835,251)	(845,033)
Proceeds from the sale of discontinued operations	—	—	153,023
Other, net	377	(2,325)	(4,904)
Net cash used in investing activities	(974,755)	(837,576)	(696,914)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	254,780	(165,865)	(208,070)
Net proceeds from issuance of long-term debt	493,538	—	493,793
Net proceeds from equity offering	—	390,205	—
Settlement of Treasury lock agreements	13,364	—	(66,626)
Repayment of long-term debt	(500,000)	—	(131)
Cash dividends paid	(160,018)	(146,248)	(128,115)
Repurchase of equity awards	(7,985)	(8,717)	(5,150)
Issuance of common stock	30,952	4,274	46
Net cash provided by financing activities	124,631	73,649	85,747
Net increase (decrease) in cash and cash equivalents	(13,605)	(23,941)	1,960
Cash and cash equivalents at beginning of year	42,258	66,199	64,239
Cash and cash equivalents at end of year	$28,653	$42,258	$66,199
CASH PAID (RECEIVED) DURING THE PERIOD FOR:			
Interest	$151,334	$156,606	$148,461
Income taxes	$1,802	$(610)	$10,008

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 serving approximately 148,000 customers in Georgia, Illinois, Iowa and Missouri.

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, contingency accruals, pension and postretirement obligations, deferred income taxes, 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, 2015 and 2014 included the following:

	September 30	
	2015	2014
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[(1)]	$121,183	$162,777
Infrastructure Mechanisms[(2)]	32,813	26,948
Deferred gas costs	9,715	20,069
Recoverable loss on reacquired debt	16,319	18,877
APT annual adjustment mechanism	1,002	8,479
Rate case costs	1,533	3,757
Other	9,774	9,402
	$192,339	$250,309
Regulatory liabilities:		
Regulatory cost of removal obligation	$483,676	$490,448
Deferred gas costs	28,100	35,063
Asset retirement obligation	9,063	10,508
Deferred franchise fees	—	5,268
Other	3,693	4,472
	$524,532	$545,759

(1) Includes $16.6 million and $18.8 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest costs along with depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recovered through base rates.

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.

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 substantially all of our regulated operations. Our nonregulated segment utilizes the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $2.3 million, $1.5 million and $1.9 million was capitalized in 2015, 2014 and 2013.

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, for each of the fiscal years ended September 30, 2015, 2014 and 2013.

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 43 years.

Asset retirement obligations — We record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2015 and 2014, we had asset retirement obligations of $11.1 million and $10.5 million. Additionally, we had $4.8 million and $5.9 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.

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, 2015 and 2014, 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. We record the cash flow impact of our financial instruments in operating cash flows based upon their balance sheet classification.

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 purchased gas cost 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. For the fiscal years ended September 30, 2015, 2014 and 2013, we included unrealized gains (losses) on open contracts of $(2.4) million, $9.6 million and $9.0 million as a component of nonregulated purchased gas cost.

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, 2015 and 2014, the Company netted $43.5 million and $25.8 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 currently manage this risk through the use of forward starting interest rate swaps 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 the Atmos Energy Corporation Master Retirement Trust (the 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.

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 when 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 is amortized over the expected future working lifetime of the plan participants.

The expected return on plan assets is then calculated by applying the expected long-term rate of return on plan assets to the market-related value of the plan assets. 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 6 regarding the new mortality tables adopted for our pension plans and the approval of the merger of the AEH 401(k) Plan with the Retirement Savings Plan, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — In May 2014, the Financial Accounting Standards Board (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. On July 9, 2015, the FASB voted to approve a deferral of the effective date of the new standard by one year. With the one-year extension, the new standard is currently scheduled to become effective for us beginning on October 1, 2018 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 April 2015, the FASB issued guidance to simplify the presentation of debt issuance costs, which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The new standard will be effective for us beginning on October 1, 2016, and will be applied retrospectively. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In April 2015, the FASB issued guidance to simplify the accounting for fees paid in connection with arrangements with cloud-based software providers. Under the new guidance, unless a software arrangement includes specific elements enabling customers to possess and operate software on platforms other than that offered by the cloud-based provider, the cost of such arrangements is to be accounted for as an operating expense in the period incurred. The new guidance is effective for us beginning October 1, 2016 and may be applied either prospectively or retrospectively with early adoption permitted. We anticipate the adoption of this standard will not have a material impact on our financial position, results of operations and cash flows.

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

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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, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,757,585	$97,662	$1,286,889	$—	$4,142,136
Intersegment revenues	6,250	272,450	185,320	(464,020)	—
	2,763,835	370,112	1,472,209	(464,020)	4,142,136
Purchased gas cost	1,526,258	—	1,399,349	(463,488)	2,462,119
Gross profit	1,237,577	370,112	72,860	(532)	1,680,017
Operating expenses					
Operation and maintenance	388,486	118,866	35,048	(532)	541,868
Depreciation and amortization	223,048	47,236	4,512	—	274,796
Taxes, other than income	205,894	22,743	3,321	—	