ATMOS ENERGY CORP
Form 10-Q
August 03, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
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)

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

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 website, 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer 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 Exchange Act) Yes ¨ No þ

Number of shares outstanding of each of the issuer's classes of common stock, as of July 29, 2016.

Class	Shares Outstanding
No Par Value	103,847,858

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody’s	Moody’s Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor’s Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2016	September 30, 2015
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$9,972,415	$9,240,100
Less accumulated depreciation and amortization	1,918,868	1,809,520
Net property, plant and equipment	8,053,547	7,430,580
Current assets		
Cash and cash equivalents	66,206	28,653
Accounts receivable, net	277,362	295,160
Gas stored underground	244,841	236,603
Other current assets	60,504	65,890
Total current assets	648,913	626,306
Goodwill	742,702	742,702
Deferred charges and other assets	282,206	293,357
	$9,727,368	$9,092,945
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2016 — 103,827,358 shares; September 30, 2015 — 101,478,818 shares	$519	$507
Additional paid-in capital	2,371,381	2,230,591
Accumulated other comprehensive loss	(178,233)	(109,330)
Retained earnings	1,273,057	1,073,029
Shareholders' equity	3,466,724	3,194,797
Long-term debt	2,205,645	2,455,388
Total capitalization	5,672,369	5,650,185
Current liabilities		
Accounts payable and accrued liabilities	198,882	238,942
Other current liabilities	410,452	457,954
Short-term debt	670,466	457,927
Current maturities of long-term debt	250,000	—
Total current liabilities	1,529,800	1,154,823
Deferred income taxes	1,585,500	1,411,315
Regulatory cost of removal obligation	427,332	427,553
Pension and postretirement liabilities	283,579	287,373
Deferred credits and other liabilities	228,788	161,696
	$9,727,368	$9,092,945

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$414,226	$416,794
Regulated pipeline segment	109,249	97,008
Nonregulated segment	214,555	278,769
Intersegment eliminations	(105,114)	(106,170)
	632,916	686,401
Purchased gas cost		
Regulated distribution segment	138,845	149,775
Regulated pipeline segment	—	—
Nonregulated segment	191,741	260,990
Intersegment eliminations	(104,981)	(106,037)
	225,605	304,728
Gross profit	407,311	381,673
Operating expenses		
Operation and maintenance	137,444	132,447
Depreciation and amortization	73,459	68,444
Taxes, other than income	59,244	63,175
Total operating expenses	270,147	264,066
Operating income	137,164	117,607
Miscellaneous income	833	634
Interest charges	27,698	27,955
Income before income taxes	110,299	90,286
Income tax expense	39,106	34,005
Net income	$71,193	$56,281
Basic and diluted net income per share	$0.69	$0.55
Cash dividends per share	$0.42	$0.39
Basic and diluted weighted average shares outstanding	103,750	102,000

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$1,902,513	$2,394,179
Regulated pipeline segment	299,629	272,305
Nonregulated segment	774,474	1,179,379
Intersegment eliminations	(305,186)	(360,629)
	2,671,430	3,485,234
Purchased gas cost		
Regulated distribution segment	884,529	1,397,113
Regulated pipeline segment	—	—
Nonregulated segment	722,803	1,122,655
Intersegment eliminations	(304,787)	(360,230)
	1,302,545	2,159,538
Gross profit	1,368,885	1,325,696
Operating expenses		
Operation and maintenance	395,958	384,489
Depreciation and amortization	216,670	204,059
Taxes, other than income	172,872	181,606
Total operating expenses	785,500	770,154
Operating income	583,385	555,542
Miscellaneous expense	(1,061)	(2,634)
Interest charges	85,741	85,166
Income before income taxes	496,583	467,742
Income tax expense	180,719	176,182
Net income	$315,864	$291,560
Basic and diluted net income per share	$3.06	$2.86
Cash dividends per share	$1.26	$1.17
Basic and diluted weighted average shares outstanding	103,137	101,776

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(Unaudited) (In thousands)			
Net income	$71,193	$56,281	$315,864	$291,560
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $110, $(41), $(837) and $(170)	151	(191)	(1,496)	(296)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(22,561), $31,314, $(50,631) and $(17,232)	(39,250)	54,475	(88,085)	(29,981)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $11,575, $7,393, $13,220 and $(12,698)	18,105	11,563	20,678	(19,571)
Total other comprehensive income (loss)	(20,994)	65,847	(68,903)	(49,848)
Total comprehensive income	$50,199	$122,128	$246,961	$241,712

See accompanying notes to condensed consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$315,864	$291,560
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	216,670	204,059
Charged to other accounts	983	853
Deferred income taxes	171,042	164,627
Other	19,767	18,146
Net assets / liabilities from risk management activities	(8,357)	(13,136)
Net change in operating assets and liabilities	(91,371)	51,473
Net cash provided by operating activities	624,598	717,582
Cash Flows From Investing Activities		
Capital expenditures	(796,008)	(667,483)
Other, net	1,627	(1,119)
Net cash used in investing activities	(794,381)	(668,602)
Cash Flows From Financing Activities		
Net increase in short-term debt	212,539	48,830
Net proceeds from equity offering	98,660	—
Issuance of common stock through stock purchase and employee retirement plans	26,500	20,813
Net proceeds from issuance of long-term debt	—	493,538
Settlement of interest rate agreements	—	13,364
Repayment of long-term debt	—	(500,000)
Cash dividends paid	(130,363)	(116,645)
Repurchase of equity awards	—	(7,985)
Net cash provided by (used in) financing activities	207,336	(48,085)
Net increase in cash and cash equivalents	37,553	895
Cash and cash equivalents at beginning of period	28,653	42,258
Cash and cash equivalents at end of period	$66,206	$43,153

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2016

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 other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated distribution business, we deliver natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six regulated distribution divisions, which at June 30, 2016, covered service areas located in eight states. In addition, we transport natural gas for others through our distribution system. Our regulated businesses also include our regulated pipeline and storage operations, which include the transportation of natural gas to our North Texas distribution system and the management of our underground storage facilities. Our regulated businesses are 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 nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy, and third parties.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company’s audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2016 are not indicative of our results of operations for the full 2016 fiscal year, which ends September 30, 2016.

No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015.

Certain prior-year amounts have been reclassified to conform with the current year presentation.

During the second quarter of fiscal 2016, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

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. 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. As of June 30, 2016, we were actively evaluating all of our sources of revenue to determine the potential effect on our financial position, results of operations and cash flows and the transition approach we will utilize. We are also actively monitoring the deliberations of the FASB's Transition Resource Group as decisions made by this group will impact the final conclusions of this evaluation.

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.
In November 2015, the FASB issued guidance that requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. As permitted under the new guidance, we elected early adoption as of March 31, 2016. The adoption of this guidance had no impact on our results of operations or cash flows. Because we adopted this new guidance prospectively, prior periods have not been adjusted.
In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.
In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. We are currently evaluating the effect on our financial position, results of operations and cash flows.
In March 2016, the FASB issued guidance to simplify the accounting and reporting of share-based payment arrangements. Key modifications required under the new guidance include:

- Recognition of all excess tax benefits and tax deficiencies associated with stock-based compensation as income tax expense or benefit in the income statement in the period the awards vest. The guidance also requires these income tax inflows and outflows to be classified as an operating activity.
- Simplification of the accounting for forfeitures.
- Clarification that cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity.

As permitted under the new guidance, we elected early adoption as of March 31, 2016. In accordance with the transition requirements, we recorded a $3.3 million income tax benefit during the first six months of fiscal 2016. Additionally, we recorded a $14.5 million cumulative-effect increase to retained earnings with an offsetting increase to the Company’s net operating loss (NOL) deferred tax asset to recognize the effect of excess tax benefits earned prior to September 30, 2015. For the nine months ended June 30, 2016, we have recognized a total income tax benefit of $4.9 million. Since we have adopted this new guidance prospectively, prior periods have not been adjusted.
In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance.
Regulatory assets and liabilities
Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of

deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2016 and September 30, 2015 included the following:

	June 30, 2016	September 30, 2015
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[(1)]	$110,425	$ 121,183
Infrastructure mechanisms[(2)]	31,090	32,813
Deferred gas costs	3,390	9,715
Recoverable loss on reacquired debt	14,401	16,319
APT annual adjustment mechanism	2,976	1,002
Rate case costs	1,640	1,533
Other	20,906	9,774
	$184,828	$ 192,339
Regulatory liabilities:		
Regulatory cost of removal obligations	$486,290	$ 483,676
Deferred gas costs	34,362	28,100
Asset retirement obligations	9,063	9,063
Other	5,483	3,693
	$535,198	$ 524,532

(1) Includes $12.9 million and $16.6 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 consist of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

3. Segment Information

We operate the Company through the following three segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our regulated distribution segment operations are geographically dispersed, they are reported as a single segment as each regulated distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine months ended June 30, 2016 and 2015 by segment are presented in the following tables:

	Three Months Ended June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$411,982	$28,518	$ 192,416	$ —	$ 632,916
Intersegment revenues	2,244	80,731	22,139	(105,114)	—
	414,226	109,249	214,555	(105,114)	632,916
Purchased gas cost	138,845	—	191,741	(104,981)	225,605
Gross profit	275,381	109,249	22,814	(133)	407,311
Operating expenses					
Operation and maintenance	100,859	29,083	7,635	(133)	137,444
Depreciation and amortization	58,916	13,409	1,134	—	73,459
Taxes, other than income	52,377	6,220	647	—	59,244
Total operating expenses	212,152	48,712	9,416	(133)	270,147
Operating income	63,229	60,537	13,398	—	137,164
Miscellaneous income (expense)	1,111	(359)	574	(493)	833
Interest charges	18,968	9,002	221	(493)	27,698
Income before income taxes	45,372	51,176	13,751	—	110,299
Income tax expense	15,516	18,046	5,544	—	39,106
Net income	$29,856	$33,130	$ 8,207	$ —	$ 71,193
Capital expenditures	$191,202	$66,639	$ (66)	$ —	$ 257,775

	Three Months Ended June 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$415,160	$25,859	$ 245,382	$ —	$ 686,401
Intersegment revenues	1,634	71,149	33,387	(106,170)	—
	416,794	97,008	278,769	(106,170)	686,401
Purchased gas cost	149,775	—	260,990	(106,037)	304,728
Gross profit	267,019	97,008	17,779	(133)	381,673
Operating expenses					
Operation and maintenance	98,552	26,572	7,456	(133)	132,447
Depreciation and amortization	55,491	11,816	1,137	—	68,444
Taxes, other than income	56,176	6,193	806	—	63,175
Total operating expenses	210,219	44,581	9,399	(133)	264,066
Operating income	56,800	52,427	8,380	—	117,607
Miscellaneous income (expense)	1,045	(211)	345	(545)	634
Interest charges	19,961	8,299	240	(545)	27,955
Income before income taxes	37,884	43,917	8,485	—	90,286
Income tax expense	15,420	15,349	3,236	—	34,005
Net income	$22,464	$28,568	$ 5,249	$ —	$ 56,281
Capital expenditures	$170,134	$55,914	$ (209)	$ —	$ 225,839

	Nine Months Ended June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$1,896,636	$75,344	$ 699,450	$ —	$2,671,430
Intersegment revenues	5,877	224,285	75,024	(305,186)	—
	1,902,513	299,629	774,474	(305,186)	2,671,430
Purchased gas cost	884,529	—	722,803	(304,787)	1,302,545
Gross profit	1,017,984	299,629	51,671	(399)	1,368,885
Operating expenses					
Operation and maintenance	291,388	83,302	21,667	(399)	395,958
Depreciation and amortization	173,913	39,358	3,399	—	216,670
Taxes, other than income	152,324	18,529	2,019	—	172,872
Total operating expenses	617,625	141,189	27,085	(399)	785,500
Operating income	400,359	158,440	24,586	—	583,385
Miscellaneous income (expense)	209	(1,164)	1,245	(1,351)	(1,061)
Interest charges	58,390	27,294	1,408	(1,351)	85,741
Income before income taxes	342,178	129,982	24,423	—	496,583
Income tax expense	124,755	46,081	9,883	—	180,719
Net income	$217,423	$83,901	$ 14,540	$ —	$315,864
Capital expenditures	$533,826	$262,058	$ 124	$ —	$796,008

	Nine Months Ended June 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,389,037	$70,887	$ 1,025,310	$ —	$3,485,234
Intersegment revenues	5,142	201,418	154,069	(360,629)	—
	2,394,179	272,305	1,179,379	(360,629)	3,485,234
Purchased gas cost	1,397,113	—	1,122,655	(360,230)	2,159,538
Gross profit	997,066	272,305	56,724	(399)	1,325,696
Operating expenses					
Operation and maintenance	288,962	74,029	21,897	(399)	384,489
Depreciation and amortization	165,730	34,945	3,384	—	204,059
Taxes, other than income	162,759	16,296	2,551	—	181,606
Total operating expenses	617,451	125,270	27,832	(399)	770,154
Operating income	379,615	147,035	28,892	—	555,542
Miscellaneous income (expense)	(1,221)	(842)	897	(1,468)	(2,634)
Interest charges	60,914	25,014	706	(1,468)	85,166
Income before income taxes	317,480	121,179	29,083	—	467,742
Income tax expense	121,776	42,894	11,512	—	176,182
Net income	$195,704	$78,285	$ 17,571	$ —	$291,560
Capital expenditures	$482,371	$185,028	$ 84	$ —	$667,483

Balance sheet information at June 30, 2016 and September 30, 2015 by segment is presented in the following tables:

	June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$6,067,548	$1,935,087	$ 50,912	$—	$ 8,053,547
Investment in subsidiaries	1,007,787	—	—	(1,007,787)	—
Current assets					
Cash and cash equivalents	61,441	—	4,765	—	66,206
Assets from risk management activities	3,651	—	4,047	—	7,698
Other current assets	370,444	22,269	391,265	(208,969)	575,009
Intercompany receivables	981,651	—	—	(981,651)	—
Total current assets	1,417,187	22,269	400,077	(1,190,620)	648,913
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	750	—	908	—	1,658
Deferred charges and other assets	258,370	21,976	202	—	280,548
	$9,327,091	$2,111,874	$ 486,810	$(2,198,407)	$ 9,727,368
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$3,466,724	$661,175	$ 346,612	$(1,007,787)	$ 3,466,724
Long-term debt	2,205,645	—	—	—	2,205,645
Total capitalization	5,672,369	661,175	346,612	(1,007,787)	5,672,369
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	870,466	—	—	(200,000)	670,466
Liabilities from risk management activities	56,883	—	—	—	56,883
Other current liabilities	453,831	16,590	90,999	(8,969)	552,451
Intercompany payables	—	953,683	27,968	(981,651)	—
Total current liabilities	1,631,180	970,273	118,967	(1,190,620)	1,529,800
Deferred income taxes	1,093,755	480,336	11,409	—	1,585,500
Noncurrent liabilities from risk management activities	176,491	—	—	—	176,491
Regulatory cost of removal obligation	427,332	—	—	—	427,332
Pension and postretirement liabilities	283,579	—	—	—	283,579
Deferred credits and other liabilities	42,385	90	9,822	—	52,297
	$9,327,091	$2,111,874	$ 486,810	$(2,198,407)	$ 9,727,368

	September 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$5,670,306	$1,706,449	$ 53,825	$—	$ 7,430,580
Investment in subsidiaries	1,038,670	—	(2,096)	(1,036,574)	—
Current assets					
Cash and cash equivalents	23,863	—	4,790	—	28,653
Assets from risk management activities	378	—	8,854	—	9,232
Other current assets	421,591	24,628	480,503	(338,301)	588,421
Intercompany receivables	887,713	—	—	(887,713)	—
Total current assets	1,333,545	24,628	494,147	(1,226,014)	626,306
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	368	—	—	—	368
Deferred charges and other assets	270,372	17,288	5,329	—	292,989
	$8,888,710	$1,880,907	$ 585,916	$(2,262,588)	$ 9,092,945
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$3,194,797	$577,275	$ 461,395	$(1,038,670)	$ 3,194,797
Long-term debt	2,455,388	—	—	—	2,455,388
Total capitalization	5,650,185	577,275	461,395	(1,038,670)	5,650,185
Current liabilities					
Short-term debt	782,927	—	—	(325,000)	457,927
Liabilities from risk management activities	9,568	—	—	—	9,568
Other current liabilities	569,273	29,780	99,480	(11,205)	687,328
Intercompany payables	—	867,409	20,304	(887,713)	—
Total current liabilities	1,361,768	897,189	119,784	(1,223,918)	1,154,823
Deferred income taxes	1,008,091	406,254	(3,030)	—	1,411,315
Noncurrent liabilities from risk management activities	110,539	—	—	—	110,539
Regulatory cost of removal obligation	427,553	—	—	—	427,553
Pension and postretirement liabilities	287,373	—	—	—	287,373
Deferred credits and other liabilities	43,201	189	7,767	—	51,157
	$8,888,710	$1,880,907	$ 585,916	$(2,262,588)	$ 9,092,945

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and nine months ended June 30, 2016 and 2015 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands, except per share amounts)			
Basic and Diluted Earnings Per Share				
Net income	$71,193	$56,281	$315,864	$291,560
Less: Income allocated to participating securities	108	111	496	596
Income available to common shareholders	$71,085	$56,170	$315,368	$290,964
Basic and diluted weighted average shares outstanding	103,750	102,000	103,137	101,776
Net income per share - Basic and Diluted	$0.69	$0.55	$3.06	$2.86

5. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 5 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Except as noted below, there were no material changes in the terms of our debt instruments during the nine months ended June 30, 2016.

Long-term debt

Long-term debt at June 30, 2016 and September 30, 2015 consisted of the following:

	June 30, 2016	September 30, 2015
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 2017	$250,000	$250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	500,000
Unsecured 4.125% Senior Notes, due 2044	500,000	500,000
Medium-term note Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Total long-term debt	2,460,000	2,460,000
Less:		
Original issue discount on unsecured senior notes and debentures	4,355	4,612
Current maturities	250,000	—
	$2,205,645	$2,455,388

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million unsecured 4.95% senior notes. The effective rate of these notes is 4.086%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014.

Short-term debt

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We currently finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At June 30, 2016 and September 30, 2015 a total of $670.5 million and $457.9 million was outstanding under our commercial paper program.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 billion, a $25 million unsecured facility, which was renewed on April 1, 2016, and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.1 million at June 30, 2016.

In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH, which bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2016.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million bilateral credit facility that was renewed and extended in March 2016 and one committed $15 million bilateral credit facility that was renewed and extended in December 2015. The uncommitted $25 million bilateral credit facility currently expires in December 2016 and the $15 million bilateral credit facility expires in September 2016. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $33.0 million at June 30, 2016.

AEH has a $500 million intercompany demand credit facility with AEC. This facility bears interest at a rate equal to the one-month LIBOR rate plus 3.00 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2016.

Debt Covenants

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2016, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 49 percent. In addition, both the interest margin and the fee that we pay on unused amounts under certain of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

We were in compliance with all of our debt covenants as of June 30, 2016. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Shareholders' Equity

Shelf Registration

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016. At June 30, 2016, $2.4 billion of securities remain available for issuance under the shelf registration statement.

At-the-Market Equity Sales Program

On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement (the Agreement) with Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC in their capacity as agents and/or as principals (Agents). Under the terms of the Agreement, we may issue and sell, through any of the Agents, shares of our common stock, up to an aggregate offering price of $200 million, through the period ended March 28, 2019. We may also sell shares from time to time to an Agent for its own account at a price to be agreed upon at the time of sale. We will pay each Agent a commission of 1.0% of the gross offering proceeds of the shares sold through it as a sales agent. We have no obligation to offer or sell any shares under the Agreement, and may at any time suspend offers and sales under the Agreement. The shares will be issued pursuant to our shelf registration statement filed with the SEC on March 28, 2016. During the third fiscal quarter of 2016, we sold 1,360,756 shares of common stock under the ATM program for $100.0 million and received net proceeds of $98.7 million.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

As of September 30, 2015, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. In February 2016, our shareholders voted to increase the number of authorized LTIP shares by 2.5 million shares and to extend the term of the plan for an additional five years, through September 2021. On March 29, 2016, we filed with the SEC a registration statement on Form S-8 to register an additional 2.5 million shares; we also listed such shares with the New York Stock Exchange.

2011 Share Repurchase Program

We did not repurchase any shares during the nine months ended June 30, 2016 and 2015 under our 2011 share repurchase program, which is scheduled to end on September 30, 2016.

Accumulated Other Comprehensive Income (Loss)

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

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2015	$4,949	$(88,842)	$(25,437)	$(109,330)
Other comprehensive loss before reclassifications	(1,417)	(88,345)	(8,612)	(98,374)
Amounts reclassified from accumulated other comprehensive income	(79)	260	29,290	29,471
Net current-period other comprehensive income (loss)	(1,496)	(88,085)	20,678	(68,903)
June 30, 2016	$3,453	$(176,927)	$(4,759)	$(178,233)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2014	$7,662	$(18,381)	$(1,674)	$(12,393)
Other comprehensive income (loss) before reclassifications	30	(30,436)	(37,397)	(67,803)
Amounts reclassified from accumulated other comprehensive income	(326)	455	17,826	17,955
Net current-period other comprehensive income (loss)	(296)	(29,981)	(19,571)	(49,848)
June 30, 2015	$7,366	$(48,362)	$(21,245)	$(62,241)

The following tables detail reclassifications out of AOCI for the three and nine months ended June 30, 2016 and 2015. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended June 30, 2016	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Cash flow hedges		
Interest rate agreements	$(137)	Interest charges
Commodity contracts	(12,347)	Purchased gas cost
	(12,484)	Total before tax
	4,865	Tax benefit
Total reclassifications	$(7,619)	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended June 30, 2015 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
Available-for-sale securities	$508		Operation and maintenance expense
	508		Total before tax
	(186	)	Tax expense
	$322		Net of tax
Cash flow hedges			
Interest rate agreements	$(137	)	Interest charges
Commodity contracts	(16,488	)	Purchased gas cost
	(16,625	)	Total before tax
	6,480		Tax benefit
	$(10,145	)	Net of tax
Total reclassifications	$(9,823	)	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2016 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
Available-for-sale securities	$124		Operation and maintenance expense
	124		Total before tax
	(45	)	Tax expense
	$79		Net of tax
Cash flow hedges			
Interest rate agreements	$(410	)	Interest charges
Commodity contracts	(48,015	)	Purchased gas cost
	(48,425	)	Total before tax
	18,875		Tax benefit
	$(29,550	)	Net of tax
Total reclassifications	$(29,471	)	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2015 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
Available-for-sale securities	$514		Operation and maintenance expense
	514		Total before tax
	(188	)	Tax expense
	$326		Net of tax

Cash flow hedges		
Interest rate agreements	$(717)	Interest charges
Commodity contracts	(29,222)	Purchased gas cost
	(29,939)	Total before tax
	11,658	Tax benefit
	$(18,281)	Net of tax
Total reclassifications	$(17,955)	Net of tax

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7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and nine months ended June 30, 2016 and 2015 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$4,698	$5,051	$2,705	$3,895
Interest cost	7,095	6,698	3,106	3,596
Expected return on assets	(6,881)	(6,435)	(1,566)	(1,608)
Amortization of transition obligation	—	—	21	69
Amortization of prior service credit	(57)	(48)	(411)	(411)
Amortization of actuarial (gain) loss	3,319	3,916	(541)	—
Net periodic pension cost	$8,174	$9,182	$3,314	$5,541

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$14,093	$15,153	$8,117	$11,687
Interest cost	21,284	20,095	9,318	10,789
Expected return on assets	(20,642)	(19,308)	(4,698)	(4,824)
Amortization of transition obligation	—	—	62	205
Amortization of prior service credit	(170)	(144)	(1,233)	(1,233)
Amortization of actuarial (gain) loss	9,959	11,749	(1,625)	—
Net periodic pension cost	$24,524	$27,545	$9,941	$16,624

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2016 and 2015 are as follows:

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.55%	4.43%	4.55%	4.43%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.25%	4.45%	4.60%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plan as of January 1, 2016. Based on that determination, we are not required to make a minimum contribution to our defined benefit plan; however, we made a voluntary contribution of $15.0 million during the third quarter of fiscal 2016.

We contributed $12.8 million to our other post-retirement benefit plans during the nine months ended June 30, 2016. We expect to contribute between $15 million and $25 million to these plans during fiscal 2016.

8. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 10 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2016.

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

Purchase Commitments

Our regulated distribution divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division 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 prices indexed to natural gas distribution hubs. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. There were no material changes to the purchase commitments for the nine months ended June 30, 2016.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Except for purchases made in the normal course of business under these contracts, there were no material changes to the purchase commitments for the nine months ended June 30, 2016.

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2016.

Regulatory Matters

Various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, continue to adopt regulations implementing many of the provisions of the Dodd-Frank Act of 2010. We continue to enact new procedures and modify existing business practices and contractual arrangements to comply with such regulations. Additional rulemakings are pending which we believe will result in new reporting and disclosure obligations. The costs associated with hedging certain risks inherent in our business may be further increased when these expected additional regulations are adopted.

As of June 30, 2016, rate cases were in progress in our Kentucky and Virginia service areas, two formula rate mechanisms were in progress in our Louisiana service area and an infrastructure mechanism was in progress in our Mississippi service area. These regulatory proceedings are discussed in further detail below in Management's Discussion and Analysis — Recent Ratemaking Developments.

9. Financial Instruments

We currently use financial instruments in our regulated distribution and nonregulated segments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments, which have been tailored to our regulated distribution and nonregulated segments, and the related accounting for these financial instruments are fully described in Notes 2 and 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. During the nine months ended June 30, 2016 there were no changes in our objectives, strategies and accounting for using financial instruments. Our financial instruments do not contain any credit-risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions. The following summarizes those objectives and strategies.

Regulated Commodity Risk Management Activities

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

We typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2015-2016 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 33 percent, or 23.0 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Nonregulated Commodity Risk Management Activities

Our nonregulated segment is exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Specifically, these operations use financial instruments in the following ways:

- Gas delivery and related services - Certain financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, are used to mitigate the commodity price risk associated with deliveries under fixed-priced forward contracts to either deliver gas to customers or purchase gas from suppliers. These financial instruments have maturity dates ranging from one to 54 months.
- Transportation and storage services - Our nonregulated operations use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.
- Aggregating and purchasing gas supply - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

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

As of June 30, 2016, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the swaps were executed. As of June 30, 2016, we had $18.4 million of net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2045.

Quantitative Disclosures Related to Financial Instruments

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

As of June 30, 2016, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2016, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Regulated Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(35,118)
	Cash Flow	—	45,325
	Not designated	10,002	51,128

10,002 61,335

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Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2016 and September 30, 2015. The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

	Balance Sheet Location	Regulated Distribution		Nonregulated	
		Assets	Liabilities	Assets	Liabilities
		(In thousands)			
June 30, 2016					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$10,149	$(35,680)
Interest rate contracts	Other current assets / Other current liabilities	—	(65,533)	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	3,911	(3,831)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(184,131)	—	—
Total		—	(249,664)	14,060	(39,511)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	3,651	(40)	27,247	(20,407)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	750	—	10,812	(9,983)
Total		4,401	(40)	38,059	(30,390)
Gross Financial Instruments		4,401	(249,704)	52,119	(69,901)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(51,210)	51,210
Net Financial Instruments		4,401	(249,704)	909	(18,691)
Cash collateral		—	16,330	4,046	18,691
Net Assets/Liabilities from Risk Management Activities		$4,401	$(233,374)	$4,955	$—

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	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$11,680	$(36,067)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	126	(9,918)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(110,539)	—	—
Total		—	(110,539)	11,806	(45,985)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	378	(9,568)	65,239	(65,780)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	368	—	14,318	(14,218)
Total		746	(9,568)	79,557	(79,998)
Gross Financial Instruments		746	(120,107)	91,363	(125,983)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(91,363)	91,363
Net Financial Instruments		746	(120,107)	—	(34,620)
Cash collateral		—	—	8,854	34,620
Net Assets/Liabilities from Risk Management Activities		$746	$(120,107)	$8,854	$—

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of purchased gas cost and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2016 and 2015 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $13.6 million and $3.6 million. For the nine months ended June 30, 2016 and 2015 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $18.1 million and $(0.9) million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2016 and 2015 is presented below.

Three Months Ended

	June 30	
	2016	2015
	(In thousands)	
Commodity contracts	$(22,146)	$(1,715)
Fair value adjustment for natural gas inventory designated as the hedged item	35,630	5,350
Total decrease in purchased gas cost	$13,484	$3,635
The decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(684)	$599
Timing ineffectiveness	14,168	3,036
	$13,484	$3,635

	Nine Months Ended June 30	
	2016	2015
	(In thousands)	
Commodity contracts	$(11,808)	$5,754
Fair value adjustment for natural gas inventory designated as the hedged item	29,852	(6,291)
Total (increase) decrease in purchased gas cost	$18,044	$(537)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(1,490)	$908
Timing ineffectiveness	19,534	(1,445)
	$18,044	$(537)

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost. To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2016 and 2015 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended June 30, 2016		
	Regulated Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$ (12,347)	$ (12,347)
Gain arising from ineffective portion of commodity contracts	—	66	66
Total impact on purchased gas cost	—	(12,281)	(12,281)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	—	(137)
Total Impact from Cash Flow Hedges	$(137)	$ (12,281)	$ (12,418)

	Three Months Ended June 30, 2015		
	Regulated Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$ (16,488)	$ (16,488)
Gain arising from ineffective portion of commodity contracts	—	11	11
Total impact on purchased gas cost	—	(16,477)	(16,477)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	—	(137)
Total Impact from Cash Flow Hedges	$(137)	$ (16,477)	$ (16,614)

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	Nine Months Ended June 30, 2016		
	Regulated Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$ (48,015)	$ (48,015)
Gain arising from ineffective portion of commodity contracts	—	84	84
Total impact on purchased gas cost	—	(47,931)	(47,931)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(410)	—	(410)
Total Impact from Cash Flow Hedges	$(410)	$ (47,931)	$ (48,341)

	Nine Months Ended June 30, 2015		
	Regulated Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$ (29,222)	$ (29,222)
Loss arising from ineffective portion of commodity contracts	—	(316)	(316)
Total impact on purchased gas cost	—	(29,538)	(29,538)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(717)	—	(717)
Total Impact from Cash Flow Hedges	$(717)	$ (29,538)	$ (30,255)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2016 and 2015. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$(39,337)	$54,388	$(88,345)	$(30,436)
Forward commodity contracts	10,573	1,505	(8,612)	(37,397)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	87	87	260	455
Forward commodity contracts	7,532	10,058	29,290	17,826
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$(21,145)	$66,038	$(67,407)	$(49,552)

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our interest rate agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred gains (losses) associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2016. However, the table below does not include the expected recognition in earnings of our outstanding interest rate agreements as those instruments have not yet settled.

	Interest Rate Agreements	Commodity Contracts	Total
	(In thousands)		
Next twelve months	$(372)	$(4,992)	$(5,364)
Thereafter	(18,018)	233	(17,785)
Total[(1)]	$(18,390)	$(4,759)	$(23,149)

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended June 30, 2016 and 2015 was a decrease in purchased gas cost of $1.9 million and $3.7 million. For the nine months ended June 30, 2016 and 2015 purchased gas cost (increased) decreased by $(2.8) million and $13.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

10. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. During the nine months ended June 30, 2016, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 6 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2015.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. 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), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2016 and September 30, 2015. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(2)	June 30, 2016
	(In thousands)				
Assets:					
Financial instruments					
Regulated distribution segment	$—	$ 4,401	$ —	$ —	$4,401
Nonregulated segment	—	52,119	—	(47,164)	4,955
Total financial instruments	—	56,520	—	(47,164)	9,356
Hedged portion of gas stored underground	97,860	—	—	—	97,860
Available-for-sale securities					
Money market funds	—	1,358	—	—	1,358
Registered investment companies	39,068	—	—	—	39,068
Bonds	—	31,319	—	—	31,319
Total available-for-sale securities	39,068	32,677	—	—	71,745
Total assets	$136,928	$ 89,197	$ —	$ (47,164)	$178,961
Liabilities:					
Financial instruments					
Regulated distribution segment	$—	$ 249,704	$ —	$ (16,330)	$233,374
Nonregulated segment	—	69,901	—	(69,901)	—
Total liabilities	$—	$ 319,605	$ —	$ (86,231)	$233,374

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2015
	(In thousands)				
Assets:					
Financial instruments					
Regulated distribution segment	$—	$ 746	$ —	$ —	$ 746
Nonregulated segment	—	91,363	—	(82,509)	8,854
Total financial instruments	—	92,109	—	(82,509)	9,600
Hedged portion of gas stored underground	43,901	—	—	—	43,901
Available-for-sale securities					
Money market funds	—	1,072	—	—	1,072
Registered investment companies	40,619	—	—	—	40,619
Bonds	—	32,509	—	—	32,509
Total available-for-sale securities	40,619	33,581	—	—	74,200
Total assets	$84,520	$ 125,690	$ —	$ (82,509)	$ 127,701
Liabilities:					
Financial instruments					
Regulated distribution segment	$—	$ 120,107	$ —	$ —	$ 120,107
Nonregulated segment	—	125,983	—	(125,983)	—
Total liabilities	$—	$ 246,090	$ —	$ (125,983)	$ 120,107

(1) Our Level 2 measurements consist of over-the-counter options and swaps which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of June 30, 2016, we had $16.3 million of cash held in margin accounts to collateralize certain regulated distribution financial instruments, which were used to offset current and noncurrent risk management liabilities. As of June 30, 2016, we also had $22.7 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $18.7 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $4.0 million classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2015, we had $43.5 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $34.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $8.9 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In thousands)			
As of June 30, 2016				
Domestic equity mutual funds	$28,377	$ 5,549	$ (962)	$32,964
Foreign equity mutual funds	5,357	747	—	6,104
Bonds	31,147	175	(3)	31,319
Money market funds	1,358	—	—	1,358
	$66,239	$ 6,471	$ (965)	$71,745
As of September 30, 2015				
Domestic equity mutual funds	$27,643	$ 7,332	$ (456)	$34,519
Foreign equity mutual funds	5,261	905	(66)	6,100
Bonds	32,423	106	(20)	32,509
Money market funds	1,072	—	—	1,072
	$66,399	$ 8,343	$ (542)	$74,200

At June 30, 2016 and September 30, 2015, our available-for-sale securities included $40.4 million and $41.7 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2016, we maintained investments in bonds that have contractual maturity dates ranging from July 2016 through September 2020.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund’s purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of June 30, 2016 and September 30, 2015:

	June 30, 2016	September 30, 2015

	(In thousands)	
Carrying Amount	$2,460,000	$2,460,000
Fair Value	$2,858,540	$2,669,323

11. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. During the nine months ended June 30, 2016, there were no material changes in our concentration of credit risk.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of June 30, 2016 and the related condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended June 30, 2016 and 2015 and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2016 and 2015. These financial statements are the responsibility of the Company’s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, and the related consolidated statements of income, comprehensive income, shareholders’ equity, and cash flows for the year then ended, not presented herein, and we expressed an unqualified audit opinion on those consolidated financial statements in our report dated November 6, 2015. In our opinion, the accompanying condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas

August 3, 2016

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations
INTRODUCTION
The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management’s Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2015.
Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995
The statements contained in this Quarterly Report on Form 10-Q 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 and capital 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.
OVERVIEW
Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six regulated distribution divisions, which at June 30, 2016 covered service areas located in eight states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.
Through our nonregulated businesses, we provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transmission and storage services to certain of our regulated distribution divisions and to third parties.

As discussed in Note 3, we operate the Company through the following three segments:

- the regulated distribution segment, which includes our regulated natural gas distribution and related sales operations,
-

- the regulated pipeline segment, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the nonregulated segment, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015 and include the following:

- Regulation
- Unbilled revenue
- Pension and other postretirement plans
- Contingencies
- Financial instruments and hedging activities
- Fair value measurements
- Impairment assessments

Our critical accounting policies are reviewed periodically by the Audit Committee of our Board of Directors. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2016.

RESULTS OF OPERATIONS

Executive Summary

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. To achieve this objective, we are investing in our infrastructure and seeking to achieve positive rate outcomes that benefit both our customers and the Company.

During the first nine months of fiscal 2016, we earned $315.9 million, or $3.06 per diluted share, an eight percent increase period over period. Regulated operations generated 88 and 95 percent of our consolidated net income for the three and nine months ended June 30, 2016. The following tables reflect the segregation of our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2016	2015	Change
	(In thousands, except per share data)		
Regulated operations	$62,986	$51,032	$11,954
Nonregulated operations	8,207	5,249	2,958
Net income	$71,193	$56,281	$14,912
Diluted EPS from regulated operations	$0.61	$0.50	$0.11
Diluted EPS from nonregulated operations	0.08	0.05	0.03
Consolidated diluted EPS	$0.69	$0.55	$0.14

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, except per share data)		
Regulated operations	$301,324	$273,989	$27,335
Nonregulated operations	14,540	17,571	(3,031)
Net income	$315,864	$291,560	$24,304
Diluted EPS from regulated operations	$2.92	$2.69	$0.23
Diluted EPS from nonregulated operations	0.14	0.17	(0.03)
Consolidated diluted EPS	$3.06	$2.86	$0.20

Positive rate outcomes achieved in our regulated businesses offset the effect of weather that was 25 percent warmer than the prior-year period. As of June 30, 2016, we had completed 16 regulatory proceedings resulting in an increase in annual operating income of $104.4 million and had five ratemaking efforts in progress seeking $24.5 million of additional annual operating income. Our nonregulated results in the current-year period reflect larger losses on the settlement of financial positions during a period of falling gas prices.

Capital expenditures for the first nine months of fiscal 2016 were $796.0 million. Approximately 83 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. We expect our capital expenditures to range between $1 billion and $1.1 billion for fiscal 2016. We funded our capital expenditure program primarily through operating cash flows of $624.6 million, net short-term borrowings and the issuance of common stock. On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. During the third fiscal quarter of 2016, we issued 1.4 million shares of common stock and received $98.7 million in net proceeds under the ATM program.

On May 13, 2016, Standard & Poor’s Corporation upgraded our senior unsecured debt rating to A from A- and upgraded our short-term debt rating to A-1 from A-2, with a ratings outlook of stable, citing strong financial performance largely due to our ability to timely recover capital investments.

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.

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 of return 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.

Seasonal weather patterns can also affect our regulated distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 97 percent of our residential and commercial meters in the following states for the following time periods:

Kansas, West Texas	October — May
Tennessee	October — April
Kentucky, Mississippi, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our regulated distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs mean higher bills for our customers, which may adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 75 percent of our residential and commercial margins.

Three Months Ended June 30, 2016 compared with Three Months Ended June 30, 2015

Financial and operational highlights for our regulated distribution segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$275,381	$267,019	$8,362
Operating expenses	212,152	210,219	1,933
Operating income	63,229	56,800	6,429
Miscellaneous income	1,111	1,045	66
Interest charges	18,968	19,961	(993)
Income before income taxes	45,372	37,884	7,488
Income tax expense	15,516	15,420	96
Net income	$29,856	$22,464	$7,392
Consolidated regulated distribution sales volumes — MMcf	34,983	36,126	(1,143)
Consolidated regulated distribution transportation volumes — MMcf	30,416	30,134	282
Total consolidated regulated distribution throughput — MMcf	65,399	66,260	(861)
Consolidated regulated distribution average cost of gas per Mcf sold	$3.97	$4.15	$(0.18)

Income for our regulated distribution segment increased 33 percent, primarily due to an $8.4 million increase in gross profit, partially offset with a $1.9 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $6.5 million net increase in rate adjustments, primarily in our Mississippi, Louisiana, West Texas and Kentucky/Mid-States Divisions.
- Customer growth, primarily in our Mid-Tex, Louisiana and Tennessee service areas, which contributed an incremental $1.5 million.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to higher levels of system maintenance and higher depreciation expense associated with increased capital investments.

Net income for the three months ended June 30, 2016 includes a $1.6 million income tax benefit for equity awards that vested during the current-year quarter as a result of adopting the new stock-based accounting guidance.

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The following table shows our operating income by regulated distribution division, in order of total rate base, for the three months ended June 30, 2016 and 2015. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2016	2015	Change
	(In thousands)		
Mid-Tex	$33,818	$33,473	$345
Kentucky/Mid-States	6,955	10,104	(3,149)
Louisiana	9,288	6,561	2,727
West Texas	5,709	5,018	691
Mississippi	3,959	1,546	2,413
Colorado-Kansas	3,152	1,872	1,280
Other	348	(1,774)	2,122
Total	$63,229	$56,800	$6,429

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

Financial and operational highlights for our regulated distribution segment for the nine months ended June 30, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$1,017,984	$997,066	$20,918
Operating expenses	617,625	617,451	174
Operating income	400,359	379,615	20,744
Miscellaneous income (expense)	209	(1,221)	1,430
Interest charges	58,390	60,914	(2,524)
Income before income taxes	342,178	317,480	24,698
Income tax expense	124,755	121,776	2,979
Net income	$217,423	$195,704	$21,719
Consolidated regulated distribution sales volumes — MMcf	215,632	265,503	(49,871)
Consolidated regulated distribution transportation volumes — MMcf	103,304	107,205	(3,901)
Total consolidated regulated distribution throughput — MMcf	318,936	372,708	(53,772)
Consolidated regulated distribution average cost of gas per Mcf sold	$4.10	$5.26	$(1.16)

Income for our regulated distribution segment increased 11 percent, primarily due to a $20.9 million increase in gross profit. The year-over-year increase in gross profit primarily reflects:

- a $37.2 million net increase in rate adjustments. Our Mid-Tex Division accounted for $16.3 million of this increase. We also experienced increases in our Mississippi and West Texas Divisions.
- The impact of weather that was 25 percent warmer than the prior-year period, before adjusting for weather normalization mechanisms. Therefore, although sales volumes declined 19 percent, gross margin experienced just a $3.6 million decline from lower consumption. Warmer weather also contributed to a $2.5 million decrease in service and other revenues.
- Customer growth, primarily in our Mid-Tex, Louisiana and Tennessee service areas, which contributed an incremental $4.9 million.
- a $14.5 million decrease in revenue-related taxes primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $15.4 million decrease in the related tax expense.

Net income for the nine months ended June 30, 2016 includes a $4.9 million income tax benefit for equity awards that vested during the current-year period as a result of adopting the new stock-based accounting guidance.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the nine months ended June 30, 2016 and 2015. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands)		
Mid-Tex	$182,594	$166,586	$16,008
Kentucky/Mid-States	56,334	59,256	(2,922)
Louisiana	48,082	47,380	702
West Texas	38,937	33,820	5,117
Mississippi	40,491	37,356	3,135
Colorado-Kansas	31,308	29,129	2,179
Other	2,613	6,088	(3,475)
Total	$400,359	$379,615	$20,744

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first nine months of fiscal 2016, we completed 15 regulatory proceedings, resulting in a $63.7 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 59,414
Rate case filings	4,456
Other rate activity	(183)
	$ 63,687

Additionally, the following ratemaking efforts seeking $24.5 million in annual operating income were in progress as of June 30, 2016:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	Rate Case (1)	Kentucky	$ 5,531
Kentucky/Mid-States	Expedited Rate Filing(2)	Virginia	537
Louisiana	Formula Rate Mechanism(2)	Trans LA	6,216
Louisiana	Formula Rate Mechanism(2)	LGS	8,686
Mississippi	Infrastructure Mechanism	Mississippi	3,519
			$ 24,489

(1) The parties filed a unanimous settlement that, if accepted by the Kentucky Pubic Service Commission, will result in an increase to operating revenue of $2.7 million on August 15, 2016.

(2) The proposed increase for Virginia and Louisiana customers was implemented on April 1, 2016 (Trans LA & Virginia) and July 1, 2016 (LGS), subject to refund.

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 substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with 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. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	Infrastructure Programs	Formula Rate Mechanisms
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) 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, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the nine months ended June 30, 2016.

Division	Jurisdiction	Test Year Ended	Increase in Annual Operating Income	Effective Date
		(In thousands)		
2016 Filings:				
Kentucky/Mid-States	Tennessee	05/31/2017	$ 4,888	06/01/2016
Mid-Tex	Mid-Tex Cities RRM	12/31/2015	25,816	06/01/2016
Mid-Tex	Mid-Tex DARR	09/30/2015	5,429	06/01/2016
Mid-Tex	Mid-Tex Environs	12/31/2015	1,325	05/03/2016
West Texas	West Texas Environs	12/31/2015	646	05/03/2016
West Texas	West Texas ALDC	12/31/2015	3,484	04/26/2016
Colorado-Kansas	Colorado	12/31/2016	764	01/01/2016
Mississippi	Mississippi-SRF [1]	10/31/2016	9,192	01/01/2016
Mississippi	Mississippi-SGR [2]	10/31/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky-PRP	09/30/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia-SAVE	09/30/2016	118	10/01/2015
West Texas	West Texas Cities	09/30/2015	3,716	10/01/2015
Total 2016 Filings			$ 59,414	

(1) The commission issued a final order approving a $9.2 million increase in annual operating income on December 21, 2015 with an effective date of January 1, 2016.

(2) The Mississippi Supplemental Growth Rider 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.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our 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 and ensure that we continue to deliver reliable, reasonably priced natural gas service safely to our customers. The following table summarizes the rate cases that were completed during the nine months ended June 30, 2016.

Division	State	Increase in Annual Operating Income	Effective Date
	(In thousands)		
2016 Rate Case Filings:			
Colorado-Kansas	Kansas	$ 2,372	03/17/2016
Colorado-Kansas	Colorado	2,084	01/01/2016
Total 2016 Rate Case Filings		$ 4,456	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2016.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
		(In thousands)		
2016 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem [1]	$ (183)	02/01/2016
Total 2016 Other Rate Activity			$ (183)	

(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.

Regulated Pipeline Segment

Our regulated pipeline segment consists of the pipeline and storage operations of the Atmos Pipeline–Texas Division. The Atmos Pipeline–Texas Division transports and stores natural gas for our Mid-Tex Division and third party local distribution companies and manages five underground storage facilities in Texas. We also provide interruptible transportation, storage and ancillary services to electric generation and industrial customers as well as producers, marketers and other shippers.

Our regulated pipeline segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence the volumes of gas transported for shippers through our pipeline system and the rates for such transportation.

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

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

Additionally, the Atmos Pipeline–Texas Division annually uses GRIP to recover capital costs incurred in the prior calendar year.

Three Months Ended June 30, 2016 compared with Three Months Ended June 30, 2015

Financial and operational highlights for our regulated pipeline segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$83,503	$71,989	$11,514
Third-party transportation	22,715	22,724	(9)
Storage and park and lend services	931	664	267
Other	2,100	1,631	469
Gross profit	109,249	97,008	12,241
Operating expenses	48,712	44,581	4,131
Operating income	60,537	52,427	8,110
Miscellaneous expense	(359)	(211)	(148)
Interest charges	9,002	8,299	703
Income before income taxes	51,176	43,917	7,259
Income tax expense	18,046	15,349	2,697
Net income	$33,130	$28,568	$4,562
Gross pipeline transportation volumes — MMcf	156,489	165,898	(9,409)
Consolidated pipeline transportation volumes — MMcf	128,801	134,823	(6,022)

Net income for our regulated pipeline segment increased 16 percent, primarily due to a $12.2 million increase in gross profit, offset by a $4.1 million increase in operating expenses. The increase in gross profit primarily reflects an $11.3 million increase in rates from the GRIP filings approved in fiscal 2015 and 2016.

Operating expenses increased $4.1 million, primarily due to increased levels of pipeline maintenance activities and higher depreciation expense associated with increased capital investments.

On May 3, 2016, a GRIP filing was approved by the Railroad Commission of Texas for $40.7 million of additional annual operating income, effective with bills rendered on and after May 3, 2016.

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

Financial and operational highlights for our regulated pipeline segment for the nine months ended June 30, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$224,662	$192,734	$31,928
Third-party transportation	63,597	71,203	(7,606)
Storage and park and lend services	2,495	2,737	(242)
Other	8,875	5,631	3,244
Gross profit	299,629	272,305	27,324
Operating expenses	141,189	125,270	15,919
Operating income	158,440	147,035	11,405
Miscellaneous expense	(1,164)	(842)	(322)
Interest charges	27,294	25,014	2,280
Income before income taxes	129,982	121,179	8,803
Income tax expense	46,081	42,894	3,187
Net income	$83,901	$78,285	$5,616
Gross pipeline transportation volumes — MMcf	520,233	567,906	(47,673)
Consolidated pipeline transportation volumes — MMcf	373,000	381,828	(8,828)

Net income for our regulated pipeline segment increased seven percent, primarily due to a $27.3 million increase in gross profit, partially offset by a $15.9 million increase in operating expenses. The increase in gross profit primarily reflects a $28.4 million increase in rates from the GRIP filings approved in fiscal 2015 and 2016 and a $3.6 million increase from the sale of excess retention gas. These increases were partially offset by a $4.0 million decrease in through-system volumes and lower storage and blending fees due to warmer weather in the current-year period compared to the prior-year period.

Operating expenses increased $15.9 million, primarily due to increased levels of pipeline maintenance activities to improve the safety and reliability of our system and increased property taxes and depreciation expense associated with increased capital investments.

Nonregulated Segment

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

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.

- The 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.

Three Months Ended June 30, 2016 compared with Three Months Ended June 30, 2015

Financial and operating highlights for our nonregulated segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$8,899	$10,648	$(1,749)
Storage and transportation services	3,616	3,607	9
Other	6,047	1,508	4,539
Total realized margins	18,562	15,763	2,799
Unrealized margins	4,252	2,016	2,236
Gross profit	22,814	17,779	5,035
Operating expenses	9,416	9,399	17
Operating income	13,398	8,380	5,018
Miscellaneous income	574	345	229
Interest charges	221	240	(19)
Income before income taxes	13,751	8,485	5,266
Income tax expense	5,544	3,236	2,308
Net income	$8,207	$5,249	$2,958
Gross nonregulated delivered gas sales volumes — MMcf	88,472	89,052	(580)
Consolidated nonregulated delivered gas sales volumes — MMcf	76,798	75,929	869
Net physical position (Bcf)	30.6	22.1	8.5

The $5.0 million quarter-over-quarter increase in gross profit reflects a $2.8 million increase in realized margins, combined with a $2.2 million increase in unrealized margins. The following were the key drivers for the $2.8 million increase in realized margins:

- Other realized margins increased $4.5 million. The increase primarily reflects larger settlement gains on short financial positions established during the first and second quarter of fiscal 2016.
- Margins from gas delivery and related services margins decreased $1.7 million, primarily due to a decrease in per-unit margins from 12 cents to 10 cents per Mcf, primarily due to increased demand from low-margin power generation and marketing customers due to warmer weather.

Unrealized margins increased $2.2 million, primarily due to the period-over-period favorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$37,454	$39,280	$(1,826)
Storage and transportation services	10,143	10,273	(130)
Other	(8,718)	(1,322)	(7,396)
Total realized margins	38,879	48,231	(9,352)
Unrealized margins	12,792	8,493	4,299
Gross profit	51,671	56,724	(5,053)
Operating expenses	27,085	27,832	(747)
Operating income	24,586	28,892	(4,306)
Miscellaneous income	1,245	897	348
Interest charges	1,408	706	702
Income before income taxes	24,423	29,083	(4,660)
Income tax expense	9,883	11,512	(1,629)
Net income	$14,540	$17,571	$(3,031)
Gross nonregulated delivered gas sales volumes — MMcf	292,619	319,423	(26,804)
Consolidated nonregulated delivered gas sales volumes — MMcf	257,733	272,260	(14,527)
Net physical position (Bcf)	30.6	22.1	8.5

The $5.1 million year-over-year decrease in gross profit reflects a $9.4 million decrease in realized margins, partially offset by a $4.3 million increase in unrealized margins. The following were the key drivers for the $9.4 million decrease in realized margins:

- Margins from gas delivery and related services decreased $1.8 million year-over-year. Consolidated sales volumes decreased five percent due to warmer weather. However, lower net transportation costs and other variable costs driven by fewer deliveries resulted in an increase in per-unit margins from 12 cents to 13 cents per Mcf, which partially offset the effect of reduced sales volumes.
- Other realized margins decreased $7.4 million. The decrease primarily reflects higher realized losses incurred during the first six months of fiscal 2016 on the settlement of long financial positions during a period of falling prices. Additionally, storage fees rose primarily due to increased park and loan activity. The aforementioned settlement gains realized during the third quarter partially offset these period over period decreases.

Unrealized margins increased $4.3 million, primarily due to the period-over-period favorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

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 under our short-term facilities.

We plan to continue to fund our growth through the use of operating cash flows, debt and equity securities while maintaining a balanced capital structure. To support our capital market activities, we filed a registration statement with the SEC on March 28, 2016 to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016. On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of

$200 million. The shares will be issued under our shelf registration statement. Proceeds from the ATM program will be used primarily to repay short-term debt outstanding under our $1.25 billion commercial paper program, to fund capital spending primarily to enhance the safety and reliability of our system and for general corporate purposes. During the third fiscal quarter of 2016, we issued 1.4 million shares of common stock and received $98.7 million in net proceeds under the ATM program. At June 30, 2016, $2.4 billion of securities remain available for issuance under the shelf registration statement.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2016, September 30, 2015 and June 30, 2015:

	June 30, 2016		September 30, 2015		June 30, 2015	
	(In thousands, except percentages)					
Short-term debt	$670,466	10.2 %	$457,927	7.5 %	$251,977	4.2 %
Long-term debt[(1)]	2,455,645	37.2 %	2,455,388	40.2 %	2,455,303	41.3 %
Shareholders' equity	3,466,724	52.6 %	3,194,797	52.3 %	3,238,255	54.5 %
Total	$6,592,835	100.0%	$6,108,112	100.0%	$5,945,535	100.0%

(1) In June 2017, $250 million of long-term debt will mature. We plan to issue new senior notes to replace this maturing debt. We have executed forward starting interest rate swaps to effectively fix the Treasury yield component associated with this anticipated issuance at 3.37%.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, 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 nine months ended June 30, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$624,598	$717,582	$(92,984)
Investing activities	(794,381)	(668,602)	(125,779)
Financing activities	207,336	(48,085)	255,421
Change in cash and cash equivalents	37,553	895	36,658
Cash and cash equivalents at beginning of period	28,653	42,258	(13,605)
Cash and cash equivalents at end of period	$66,206	$43,153	$23,053

Cash flows from operating activities

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and 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.

For the nine months ended June 30, 2016, we generated cash flow of $624.6 million from operating activities compared with $717.6 million for the nine months ended June 30, 2015. The $93.0 million decrease in operating cash flows primarily reflects the timing of deferred gas cost recoveries.

Cash flows from investing activities

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.

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. We anticipate our annual capital spending will be in the range of $1 billion to $1.4 billion through fiscal 2020.
For the nine months ended June 30, 2016, capital expenditures were $796.0 million, compared with $667.5 million in the prior-year period. The $128.5 million increase primarily reflects an 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 combined with a planned increase in spending in our regulated distribution operations.
Cash flows from financing activities

For the nine months ended June 30, 2016, our financing activities generated $207.3 million of cash compared with $48.1 million of cash used in the prior-year period. The $255.4 million increase of cash generated is primarily due to higher net short-term debt borrowings due to increased capital expenditures and period-over-period changes in working capital funding needs compared to the prior year, as well as proceeds received from the issuance of common stock under our ATM program in the third fiscal quarter of 2016.
The following table summarizes our share issuances for the nine months ended June 30, 2016 and 2015.

	Nine Months Ended June 30	
	2016	2015
Shares issued:		
Direct Stock Purchase Plan	107,736	137,049
1998 Long-Term Incentive Plan	597,470	664,074
Retirement Savings Plan and Trust	282,578	296,067
At-the-Market (ATM) Equity Sales Program	1,360,756	—
Total shares issued	2,348,540	1,097,190

The year-over-year increase in the number of shares issued primarily reflects shares issued under the ATM Program. For the nine months ended June 30, 2016, we did not cancel and retire any shares attributable to federal income tax withholdings on equity awards. For the nine months ended June 30, 2015, we canceled and retired 148,464 such shares.

Credit Facilities

Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business and the level of our capital expenditures. Changes in the price of natural gas, the amount of natural gas we need to supply to meet our customers' needs and our capital spending activities could significantly affect our borrowing requirements. However, our short-term borrowings typically reach their highest levels in the winter months.
We finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of June 30, 2016, the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $0.6 billion.
Credit Ratings
Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our regulated and nonregulated businesses and the regulatory structures that govern our rates in the states where we

operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings (Fitch). On May 13, 2016, S&P upgraded our senior unsecured debt rating to A from A- and upgraded our short-term debt rating to A-1 from A-2, with a ratings outlook of stable, citing strong financial performance largely due to our ability to timely recover capital investments. As of June 30, 2016, all three rating agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Senior unsecured long-term debt	A	A2	A
Short-term debt	A-1	P-1	F-2

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

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2016. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2016.

Risk Management Activities

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. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

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. 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.

The following table shows the components of the change in fair value of our regulated distribution segment's financial instruments for the three and nine months ended June 30, 2016 and 2015:

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands)			
Fair value of contracts at beginning of period	$(187,864)	$(137,710)	$(119,361)	$14,284
Contracts realized/settled	(107)	(48)	(20,865)	(33,859)
Fair value of new contracts	2,377	1,514	2,434	1,365
Other changes in value	(59,709)	85,993	(107,511)	(32,041)
Fair value of contracts at end of period	(245,303)	(50,251)	(245,303)	(50,251)

Netting of cash collateral	16,330	—	16,330	—
Cash collateral and fair value of contracts at period end	$(228,973)	$(50,251)	$(228,973)	$(50,251)

The fair value of our regulated distribution segment's financial instruments at June 30, 2016 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2016				
	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	$(61,922)	$(183,381)	$ —	$ —	$(245,303)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(61,922)	$(183,381)	$ —	$ —	$(245,303)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2016 and 2015:

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands)			
Fair value of contracts at beginning of period	$(16,085)	$(36,140)	$(34,620)	$(3,033)
Contracts realized/settled	1,303	11,502	22,050	23,013
Fair value of new contracts	—	—	—	—
Other changes in value	(3,000)	4,121	(5,212)	(40,497)
Fair value of contracts at end of period	(17,782)	(20,517)	(17,782)	(20,517)
Netting of cash collateral	22,737	31,323	22,737	31,323
Cash collateral and fair value of contracts at period end	$4,955	$10,806	$4,955	$10,806

The fair value of our nonregulated segment's financial instruments at June 30, 2016 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2016				
	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	$(18,691)	$621	$288	$ —	$(17,782)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(18,691)	$621	$288	$ —	$(17,782)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2016 and 2015, our total net periodic pension and other benefits costs were $34.5 million and $44.2 million. A substantial portion of those costs relating to our regulated distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2016 net periodic pension cost is approximately 20 percent lower than in fiscal 2015. The decrease is attributable to the net impact of changes in the various assumptions used to establish those costs as of September 30, 2015, our most recent measurement date. The most significant changes include:

- An increase in the discount rate from 4.43 percent to 4.55 percent
- A decrease in the expected return on plan assets from 7.25 percent to 7.00 percent
- Utilization of updated mortality tables issued in October 2015 by the Society of Actuaries

The amount with which we fund our defined benefit plan is determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plan when the funding requirements are determined on January 1 of each year. Based upon the determination as of January 1, 2015, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2016. However, we made a voluntary contribution of $15.0 million during the third quarter of fiscal 2016.

For the nine months ended June 30, 2016 we contributed $12.8 million to our postretirement medical plans. We anticipate contributing between $15 million and $25 million to our postretirement plans during fiscal 2016.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three and nine month periods ended June 30, 2016 and 2015.

Regulated Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
METERS IN SERVICE, end of period				
Residential	2,903,099	2,872,584	2,903,099	2,872,584
Commercial	266,435	262,353	266,435	262,353
Industrial	1,463	1,518	1,463	1,518
Public authority and other	8,377	8,419	8,377	8,419
Total meters	3,179,374	3,144,874	3,179,374	3,144,874
INVENTORY STORAGE BALANCE — Bcf	51.3	42.6	51.3	42.6
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	16,407	16,667	125,334	159,067
Commercial	14,718	15,216	73,990	87,852
Industrial	2,671	2,925	10,586	11,713
Public authority and other	1,187	1,318	5,722	6,871
Total gas sales volumes	34,983	36,126	215,632	265,503
Transportation volumes	33,367	33,743	112,477	117,019
Total throughput	68,350	69,869	328,109	382,522
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$260,634	$253,033	$1,240,184	$1,538,771
Commercial	113,075	114,942	507,580	666,220
Industrial	9,456	13,089	41,309	62,694
Public authority and other	7,309	8,465	34,402	46,355
Total gas sales revenues	390,474	389,529	1,823,475	2,314,040
Transportation revenues	18,097	16,506	60,202	57,635
Other gas revenues	5,655	10,759	18,836	22,504
Total operating revenues	$414,226	$416,794	$1,902,513	$2,394,179
Average cost of gas per Mcf sold	$3.97	$4.15	$4.10	$5.26

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
CUSTOMERS, end of period				
Industrial	767	750	767	750
Municipal	133	129	133	129
Other	518	516	518	516
Total	1,418	1,395	1,418	1,395
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	40.9	28.2	40.9	28.2
REGULATED PIPELINE VOLUMES — MMcf[1]	156,489	165,898	520,233	567,906
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	88,472	89,052	292,619	319,423
OPERATING REVENUES (000's)[1]				
Regulated pipeline	$109,249	$97,008	$299,629	$272,305
Nonregulated	214,555	278,769	774,474	1,179,379
Total operating revenues	$323,804	$375,777	$1,074,103	$1,451,684

Note to preceding tables:

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

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 unaudited condensed consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. During the nine months ended June 30, 2016, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. Controls and Procedures

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2016 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

During the nine months ended June 30, 2016, there were no material changes in the status of the litigation and other matters that were disclosed in Note 10 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. Exhibits

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)
By: /s/ BRET J. ECKERT
Bret J. Eckert
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 3, 2016

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company’s Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

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