ATMOS ENERGY CORP
Form 10-Q
May 07, 2014

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 March 31, 2014
or

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

For the transition period from to
Commission File Number 1-10042
Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

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

(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 May 1, 2014.

Class	Shares Outstanding
No Par Value	100,186,395

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
GSRS	Gas System Reliability Surcharge
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

	March 31, 2014 (Unaudited)	September 30, 2013
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$8,014,440	$7,722,019
Less accumulated depreciation and amortization	1,744,457	1,691,364
Net property, plant and equipment	6,269,983	6,030,655
Current assets		
Cash and cash equivalents	136,740	66,199
Accounts receivable, net	671,021	301,992
Gas stored underground	124,950	244,741
Other current assets	126,450	64,201
Total current assets	1,059,161	677,133
Goodwill	741,363	741,363
Deferred charges and other assets	417,109	485,117
	$8,487,616	$7,934,268
CAPITALIZATION AND LIABILITIES		
Shareholders’ equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2014 — 100,177,825 shares; September 30, 2013 — 90,640,211 shares	$501	$453
Additional paid-in capital	2,163,144	1,765,811
Retained earnings	924,282	775,267
Accumulated other comprehensive income	36,834	38,878
Shareholders’ equity	3,124,761	2,580,409
Long-term debt	1,955,829	2,455,671
Total capitalization	5,080,590	5,036,080
Current liabilities		
Accounts payable and accrued liabilities	442,816	241,611
Other current liabilities	420,576	368,891
Short-term debt	—	367,984
Current maturities of long-term debt	500,000	—
Total current liabilities	1,363,392	978,486
Deferred income taxes	1,283,551	1,164,053
Regulatory cost of removal obligation	358,262	359,299
Pension and postretirement liabilities	360,851	358,787
Deferred credits and other liabilities	40,970	37,563
	$8,487,616	$7,934,268

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,290,960	$905,176
Regulated transmission and storage segment	73,615	61,848
Nonregulated segment	757,683	428,948
Intersegment eliminations	(157,936)	(86,976)
	1,964,322	1,308,996
Purchased gas cost		
Natural gas distribution segment	905,772	558,170
Regulated transmission and storage segment	—	—
Nonregulated segment	720,094	404,641
Intersegment eliminations	(157,821)	(86,566)
	1,468,045	876,245
Gross profit	496,277	432,751
Operating expenses		
Operation and maintenance	124,675	111,086
Depreciation and amortization	61,307	57,180
Taxes, other than income	60,215	54,307
Total operating expenses	246,197	222,573
Operating income	250,080	210,178
Miscellaneous income (expense)	(1,516)	1,712
Interest charges	31,601	33,331
Income from continuing operations before income taxes	216,963	178,559
Income tax expense	83,596	66,219
Income from continuing operations	133,367	112,340
Income from discontinued operations, net of tax ($0 and $2,258)	—	4,085
Net income	$133,367	$116,425
Basic earnings per share		
Income per share from continuing operations	$1.40	$1.24
Income per share from discontinued operations	—	0.04
Net income per share — basic	$1.40	$1.28
Diluted earnings per share		
Income per share from continuing operations	$1.38	$1.23
Income per share from discontinued operations	—	0.04
Net income per share — diluted	$1.38	$1.27
Cash dividends per share	$0.37	$0.35
Weighted average shares outstanding:		
Basic	95,264	90,530
Diluted	96,191	91,492

See accompanying notes to condensed consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,134,825	$1,571,963
Regulated transmission and storage segment	144,956	122,529
Nonregulated segment	1,205,404	828,842
Intersegment eliminations	(265,715)	(180,183)
	3,219,470	2,343,151
Purchased gas cost		
Natural gas distribution segment	1,450,466	945,326
Regulated transmission and storage segment	—	—
Nonregulated segment	1,149,249	782,076
Intersegment eliminations	(265,479)	(179,364)
	2,334,236	1,548,038
Gross profit	885,234	795,113
Operating expenses		
Operation and maintenance	240,432	217,613
Depreciation and amortization	121,776	116,759
Taxes, other than income	102,226	95,641
Total operating expenses	464,434	430,013
Operating income	420,800	365,100
Miscellaneous income (expense)	(3,648)	2,410
Interest charges	63,716	63,853
Income from continuing operations before income taxes	353,436	303,657
Income tax expense	133,053	113,969
Income from continuing operations	220,383	189,688
Income from discontinued operations, net of tax ($0 and $3,986)	—	7,202
Net income	$220,383	$196,890
Basic earnings per share		
Income per share from continuing operations	$2.36	$2.09
Income per share from discontinued operations	—	0.08
Net income per share — basic	$2.36	$2.17
Diluted earnings per share		
Income per share from continuing operations	$2.34	$2.07
Income per share from discontinued operations	—	0.08
Net income per share — diluted	$2.34	$2.15
Cash dividends per share	$0.74	$0.70
Weighted average shares outstanding:		
Basic	93,049	90,445
Diluted	93,976	91,406

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(Unaudited) (In thousands)			
Net income	$133,367	$116,425	$220,383	$196,890
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(133), $(110), $1,302 and $(330)	(252)	(200)	2,142	(573)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(15,546), $13,513, $(7,533) and $20,562	(27,047)	23,509	(13,105)	35,773
Net unrealized gains on commodity cash flow hedges, net of tax of $703, $5,650, $5,702 and $5,417	1,101	8,838	8,919	8,473
Total other comprehensive income (loss)	(26,198)	32,147	(2,044)	43,673
Total comprehensive income	$107,169	$148,572	$218,339	$240,563

See accompanying notes to condensed consolidated financial statements.

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ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2014	2013
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$220,383	$196,890
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	121,776	118,608
Charged to other accounts	441	265
Deferred income taxes	119,710	106,891
Other	10,746	5,519
Net assets / liabilities from risk management activities	836	(14,709)
Net change in operating assets and liabilities	17,089	(37,123)
Net cash provided by operating activities	490,981	376,341
Cash Flows From Investing Activities		
Capital expenditures	(359,009)	(389,117)
Other, net	(4,904)	(3,700)
Net cash used in investing activities	(363,913)	(392,817)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(369,012)	(342,141)
Net proceeds from equity offering	390,205	—
Net proceeds from issuance of long-term debt	—	493,793
Settlement of Treasury lock agreements	—	(66,626)
Repayment of long-term debt	—	(131)
Cash dividends paid	(71,380)	(64,008)
Repurchase of equity awards	(6,317)	(3,124)
Other	(23)	21
Net cash provided by (used in) financing activities	(56,527)	17,784
Net increase in cash and cash equivalents	70,541	1,308
Cash and cash equivalents at beginning of period	66,199	64,239
Cash and cash equivalents at end of period	$136,740	$65,547

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2014

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. For the fiscal year ended September 30, 2013, our regulated businesses generated approximately 95 percent of our consolidated net income.

Through our natural gas 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 natural gas distribution divisions, which at March 31, 2014, covered service areas located in eight states. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers. 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 natural gas 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, 2013. 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, 2013. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2014 are not indicative of our results of operations for the full 2014 fiscal year, which ends September 30, 2014.

Except as noted in Note 7 and Note 8, 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, 2013.

During the second quarter of fiscal 2014, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Due to the April 1, 2013 sale of our Georgia distribution operations, prior year financial results for this service area are shown in discontinued operations.

Disclosure requirements for offsetting arrangements for financial instruments became effective for us beginning on October 1, 2013. We have presented these disclosures in Note 8. In connection with the adoption of this standard, prior-year risk management assets and liabilities have been reclassified to conform with the current-year presentation. The adoption of this standard and reclassification did not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies nor were there new accounting standards announced during the six months ended March 31, 2014 that will become applicable to the Company in future periods.

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 March 31, 2014 and September 30, 2013 included the following:

	March 31, 2014	September 30, 2013
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[(1)]	$176,616	$187,977
Merger and integration costs, net	4,990	5,250
Deferred gas costs	10,004	15,152
Regulatory cost of removal asset	9,716	10,008
Rate case costs	5,037	6,329
Texas Rule 8.209[(2)]	40,760	30,364
APT annual adjustment mechanism	4,084	5,853
Recoverable loss on reacquired debt	20,156	21,435
Other	6,393	4,380
	$277,756	$286,748
Regulatory liabilities:		
Deferred gas costs	$80,330	$16,481
Deferred franchise fees	11,523	1,689
Regulatory cost of removal obligation	425,461	427,524
Other	11,683	7,887
	$528,997	$453,581

(1) Includes $18.1 million and $17.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Texas Rule 8.209 is a Railroad Commission rule that allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recovered through base rates.

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years.

3. Segment Information

We operate the Company through the following three segments:

- The natural gas distribution segment, which includes our regulated natural gas distribution and related sales operations,
- The regulated transmission and storage segment, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
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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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of

significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. We evaluate performance based on net income or loss of the respective operating units.
Income statements for the three and six month periods ended March 31, 2014 and 2013 by segment are presented in the following tables:

	Three Months Ended March 31, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$1,289,429	$21,002	$653,891	$—	$1,964,322
Intersegment revenues	1,531	52,613	103,792	(157,936)	—
	1,290,960	73,615	757,683	(157,936)	1,964,322
Purchased gas cost	905,772	—	720,094	(157,821)	1,468,045
Gross profit	385,188	73,615	37,589	(115)	496,277
Operating expenses					
Operation and maintenance	106,776	16,595	1,419	(115)	124,675
Depreciation and amortization	50,020	10,156	1,131	—	61,307
Taxes, other than income	60,606	(1,232)	841	—	60,215
Total operating expenses	217,402	25,519	3,391	(115)	246,197
Operating income	167,786	48,096	34,198	—	250,080
Miscellaneous income (expense)	97	(1,081)	443	(975)	(1,516)
Interest charges	22,828	9,155	593	(975)	31,601
Income before income taxes	145,055	37,860	34,048	—	216,963
Income tax expense	56,312	13,751	13,533	—	83,596
Net income	$88,743	$24,109	$20,515	$—	$133,367
Capital expenditures	$139,555	$39,000	$(113)	$—	$178,442

	Three Months Ended March 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$904,181	$19,655	$385,160	$—	$1,308,996
Intersegment revenues	995	42,193	43,788	(86,976)	—
	905,176	61,848	428,948	(86,976)	1,308,996
Purchased gas cost	558,170	—	404,641	(86,566)	876,245
Gross profit	347,006	61,848	24,307	(410)	432,751
Operating expenses					
Operation and maintenance	89,344	15,390	6,763	(411)	111,086
Depreciation and amortization	47,631	8,690	859	—	57,180
Taxes, other than income	49,592	4,277	438	—	54,307
Total operating expenses	186,567	28,357	8,060	(411)	222,573
Operating income	160,439	33,491	16,247	1	210,178
Miscellaneous income (expense)	2,591	(99)	(91)	(689)	1,712
Interest charges	25,664	7,857	498	(688)	33,331
Income from continuing operations before income taxes	137,366	25,535	15,658	—	178,559
Income tax expense	51,176	9,005	6,038	—	66,219
Income from continuing operations	86,190	16,530	9,620	—	112,340
Income from discontinued operations, net of tax	4,085	—	—	—	4,085
Net income	$90,275	$16,530	$9,620	$—	$116,425
Capital expenditures	$131,465	$67,208	$417	$—	$199,090

	Six Months Ended March 31, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,131,861	$42,172	$1,045,437	$—	$3,219,470
Intersegment revenues	2,964	102,784	159,967	(265,715)	—
	2,134,825	144,956	1,205,404	(265,715)	3,219,470
Purchased gas cost	1,450,466	—	1,149,249	(265,479)	2,334,236
Gross profit	684,359	144,956	56,155	(236)	885,234
Operating expenses					
Operation and maintenance	196,439	33,895	10,334	(236)	240,432
Depreciation and amortization	99,571	19,942	2,263	—	121,776
Taxes, other than income	97,690	3,431	1,105	—	102,226
Total operating expenses	393,700	57,268	13,702	(236)	464,434
Operating income	290,659	87,688	42,453	—	420,800
Miscellaneous income (expense)	(374)	(2,262)	767	(1,779)	(3,648)
Interest charges	46,153	18,112	1,230	(1,779)	63,716
Income from before income taxes	244,132	67,314	41,990	—	353,436
Income tax expense	92,632	23,759	16,662	—	133,053
Net income	$151,500	$43,555	$25,328	$—	$220,383
Capital expenditures	$267,061	$91,921	$27	$—	$359,009

	Six Months Ended March 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$1,569,730	$38,354	$735,067	$—	$2,343,151
Intersegment revenues	2,233	84,175	93,775	(180,183)	—
	1,571,963	122,529	828,842	(180,183)	2,343,151
Purchased gas cost	945,326	—	782,076	(179,364)	1,548,038
Gross profit	626,637	122,529	46,766	(819)	795,113
Operating expenses					
Operation and maintenance	173,080	31,710	13,645	(822)	217,613
Depreciation and amortization	97,691	17,080	1,988	—	116,759
Taxes, other than income	86,343	8,226	1,072	—	95,641
Total operating expenses	357,114	57,016	16,705	(822)	430,013
Operating income	269,523	65,513	30,061	3	365,100
Miscellaneous income (expense)	2,460	(226)	1,576	(1,400)	2,410
Interest charges	49,227	14,728	1,295	(1,397)	63,853
Income from continuing operations before income taxes	222,756	50,559	30,342	—	303,657
Income tax expense	83,473	17,924	12,572	—	113,969
Income from continuing operations	139,283	32,635	17,770	—	189,688
Income from discontinued operations, net of tax	7,202	—	—	—	7,202
Net income	$146,485	$32,635	$17,770	$—	$196,890
Capital expenditures	$277,336	$111,039	$742	$—	$389,117

Balance sheet information at March 31, 2014 and September 30, 2013 by segment is presented in the following tables.

	March 31, 2014 Natural Gas Distribution (In thousands)	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
ASSETS					
Property, plant and equipment, net	$4,889,160	$1,322,441	$58,382	$—	$6,269,983
Investment in subsidiaries	908,939	—	(2,096)	(906,843)	—
Current assets					
Cash and cash equivalents	73,165	—	63,575	—	136,740
Assets from risk management activities	58,746	—	7,940	—	66,686
Other current assets	609,806	14,363	610,515	(378,949)	855,735
Intercompany receivables	786,428	—	—	(786,428)	—
Total current assets	1,528,145	14,363	682,030	(1,165,377)	1,059,161
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	30,665	—	8,910	—	39,575
Deferred charges and other assets	350,362	19,585	7,587	—	377,534
	$8,281,461	$1,488,851	$789,524	$(2,072,220)	$8,487,616
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$3,124,761	$439,977	$468,962	$(908,939)	$3,124,761
Long-term debt	1,955,829	—	—	—	1,955,829
Total capitalization	5,080,590	439,977	468,962	(908,939)	5,080,590
Current liabilities					
Current maturities of long-term debt	500,000	—	—	—	500,000
Short-term debt	343,000	—	—	(343,000)	—
Other current liabilities	658,106	13,654	225,485	(33,853)	863,392
Intercompany payables	—	708,046	78,382	(786,428)	—
Total current liabilities	1,501,106	721,700	303,867	(1,163,281)	1,363,392
Deferred income taxes	943,831	324,879	14,841	—	1,283,551
Regulatory cost of removal obligation	358,262	—	—	—	358,262
Pension and postretirement liabilities	360,851	—	—	—	360,851
Deferred credits and other liabilities	36,821	2,295	1,854	—	40,970
	$8,281,461	$1,488,851	$789,524	$(2,072,220)	$8,487,616

	September 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,719,873	$1,249,767	$61,015	$—	$6,030,655
Investment in subsidiaries	831,136	—	(2,096)	(829,040)	—
Current assets					
Cash and cash equivalents	4,237	—	61,962	—	66,199
Assets from risk management activities	1,837	—	10,129	—	11,966
Other current assets	428,366	11,709	452,126	(293,233)	598,968
Intercompany receivables	783,738	—	—	(783,738)	—
Total current assets	1,218,178	11,709	524,217	(1,076,971)	677,133
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	109,354	—	—	—	109,354
Deferred charges and other assets	347,687	19,227	8,849	—	375,763
	$7,800,418	$1,413,165	$626,696	$(1,906,011)	$7,934,268
CAPITALIZATION AND LIABILITIES					
Shareholders’ equity	$2,580,409	$396,421	$434,715	$(831,136)	$2,580,409
Long-term debt	2,455,671	—	—	—	2,455,671
Total capitalization	5,036,080	396,421	434,715	(831,136)	5,036,080
Current liabilities					
Current maturities of long-term debt	—	—	—	—	—
Short-term debt	645,984	—	—	(278,000)	367,984
Liabilities from risk management activities	1,543	—	—	—	1,543
Other current liabilities	491,681	20,288	110,306	(13,316)	608,959
Intercompany payables	—	712,768	70,970	(783,738)	—
Total current liabilities	1,139,208	733,056	181,276	(1,075,054)	978,486
Deferred income taxes	871,360	283,554	8,960	179	1,164,053
Regulatory cost of removal obligation	359,299	—	—	—	359,299
Pension and postretirement liabilities	358,787	—	—	—	358,787
Deferred credits and other liabilities	35,684	134	1,745	—	37,563
	$7,800,418	$1,413,165	$626,696	$(1,906,011)	$7,934,268

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 six months ended March 31, 2014 and 2013 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income from continuing operations	$133,367	$112,340	$220,383	$189,688
Less: Income from continuing operations allocated to participating securities	337	304	578	634
Income from continuing operations available to common shareholders	$133,030	$112,036	$219,805	$189,054
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Income from continuing operations per share — Basic	$1.40	$1.24	$2.36	$2.09
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$—	$4,085	$—	$7,202
Less: Income from discontinued operations allocated to participating securities	—	11	—	24
Income from discontinued operations available to common shareholders	$—	$4,074	$—	$7,178
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Income from discontinued operations per share — Basic	$—	$0.04	$—	$0.08
Net income per share — Basic	$1.40	$1.28	$2.36	$2.17

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income from continuing operations available to common shareholders	$133,030	$112,036	$219,805	$189,054
Effect of dilutive stock options and other shares	2	2	4	5
Income from continuing operations available to common shareholders	$133,032	$112,038	$219,809	$189,059
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Additional dilutive stock options and other shares	927	962	927	961
Diluted weighted average shares outstanding	96,191	91,492	93,976	91,406
Income from continuing operations per share — Diluted	$1.38	$1.23	$2.34	$2.07
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$—	$4,074	$—	$7,178
Effect of dilutive stock options and other shares	—	—	—	—
Income from discontinued operations available to common shareholders	$—	$4,074	$—	$7,178
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Additional dilutive stock options and other shares	927	962	927	961
Diluted weighted average shares outstanding	96,191	91,492	93,976	91,406
Income from discontinued operations per share — Diluted	$—	$0.04	$—	$0.08
Net income per share — Diluted	$1.38	$1.27	$2.34	$2.15

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2014 and 2013 as their exercise price was less than the average market price of the common stock during those periods.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the six months ended March 31, 2014 and 2013 under our 2011 share repurchase program.

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, 2013. Except as noted below, there were no material changes in the terms of our debt instruments during the six months ended March 31, 2014.

Long-term debt

Long-term debt at March 31, 2014 and September 30, 2013 consisted of the following:

	March 31, 2014	September 30, 2013
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$500,000	$500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	500,000
Medium-term 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	4,171	4,329
Current maturities	500,000	—
	$1,955,829	$2,455,671

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 $950 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1 billion of working capital funding. At March 31, 2014, there were no short-term debt borrowings outstanding. At September 30, 2013, there was a total of $368.0 million 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 $985 million of working capital funding, including a five-year $950 million unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.2 billion, a $25 million unsecured facility 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 March 31, 2014.

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 rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2014.

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Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, had two $25 million 364-day bilateral credit facilities that expired in December 2013. In December 2013, the $25 million 364-day uncommitted bilateral facility was extended to December 2014. In January 2014, this facility was amended to temporarily increase the amount available to $50 million to address the increase in volumes and prices driven by colder than normal weather this winter-heating season. The maximum available under the facility will return to $25 million on June 30, 2014. The $25 million committed bilateral facility was replaced with a $15 million committed 364-day bilateral credit facility in December 2013. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $33.7 million at March 31, 2014.

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 or (ii) the rate for AEM's borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2014.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, which generated net proceeds of $390.2 million. As of March 31, 2014, $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 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 March 31, 2014, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 46 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 March 31, 2014. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. 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 six months ended March 31, 2014 and 2013 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. On October 2, 2013, due to the retirement of one of our executive officers, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with the retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$4,738	$5,203	$4,196	$4,700
Interest cost	6,824	6,023	3,988	3,241
Expected return on assets	(5,900)	(5,738)	(1,292)	(997)
Amortization of transition obligation	—	—	68	270
Amortization of prior service credit	(34)	(36)	(362)	(363)
Amortization of actuarial loss	3,930	5,562	158	1,049
Net periodic pension cost	$9,558	$11,014	$6,756	$7,900

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$9,476	$10,405	$8,392	$9,400
Interest cost	13,648	12,048	7,976	6,482
Expected return on assets	(11,801)	(11,477)	(2,584)	(1,994)
Amortization of transition obligation	—	—	136	540
Amortization of prior service credit	(68)	(71)	(725)	(725)
Amortization of actuarial loss	7,862	11,123	316	2,098
Settlement loss	4,539	—	—	—
Net periodic pension cost	$23,656	$22,028	$13,511	$15,801

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2014 and 2013 are as follows:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	4.95%	4.04%	4.95%	4.04%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.25%	7.75%	4.60%	4.70%

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 plans as of January 1, 2014. During the first six months of fiscal 2014, we contributed $9.1 million to our defined benefit plans and we anticipate contributing approximately $10 million to $35 million during fiscal 2014.

We contributed $11.6 million to our other post-retirement benefit plans during the six months ended March 31, 2014. We expect to contribute a total of approximately $20 million to $25 million to these plans during fiscal 2014.

7. 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, 2013, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2014.

Kentucky Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate. Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals, appealing the verdict of the trial court. The appellees in this case subsequently filed their appellees' brief with the Court of Appeals on January 16, 2012, with our reply brief being filed with the Court of Appeals on March 19, 2012. Oral arguments were held in the case on August 27, 2012.

In an opinion handed down on January 25, 2013, the Court of Appeals overturned the $28.5 million jury verdict returned against the Atmos Entities. In a unanimous decision by a three-judge panel, the Court of Appeals reversed the claims asserted by the landowners and investors/working interest owners. The Court of Appeals concluded that all of such claims that the Atmos Entities appealed should have been dismissed by the trial court as a matter of law. The Court of Appeals let stand the jury verdict on one claim that Atmos Energy and our subsidiaries chose not to appeal, which was a trespass claim. The jury had awarded a total of $10,000 in compensatory damages to one landowner on that claim. The Court of Appeals vacated all of the other damages awarded by the jury and remanded the case to the trial court for a new trial, solely on the issue of whether punitive damages should be awarded to that landowner and, if so, in what amount.

The investors/working interest owners, on February 25, 2013, and the landowners, on March 19, 2013, each filed with the Supreme Court of Kentucky, separate motions for discretionary review of the opinion of the Court of Appeals. We filed responses to the motions. The Kentucky Supreme Court denied the motions for discretionary review on February 12, 2014. The decision of the Court of Appeals became final on February 21, 2014. Atmos has filed a motion with the trial court for entry of judgment dismissing all claims against it, except for the trespass claim. Atmos' motion seeks a ruling by the trial court that the remaining landowner is not entitled to any punitive damages on that claim. That motion is currently scheduled to be heard on May 19, 2014.

We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter. This accrual was reversed during the second fiscal quarter as the appellate process in this case has been completed.

In addition, in a related matter, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss. Discovery has been completed, and dispositive motions are due on June 30, 2014. This case is scheduled for trial beginning October 6, 2014.

Tennessee Business License Tax

Atmos Energy, through its affiliate, AEM, has been involved in a dispute with the Tennessee Department of Revenue (TDOR) regarding sales business tax audits over a period of several years. The cumulative assessment approximated $12 million as of March 31, 2014, which AEM has challenged. We had previously accrued in prior years what we believed to be an adequate amount for the anticipated resolution of this matter. With respect to certain issues, AEM and the TDOR filed competing Partial Motions for Summary Judgment with the Chancery Court. On August 2, 2013, the Chancery Court granted the TDOR's Partial Motion for Summary Judgment and denied AEM's Partial Motion for Summary Judgment. A filing deadline was set for filing any cross motions for partial summary judgment as to the remaining issues. On May 2, 2014, the Company and the TDOR executed an agreed order of dismissal with prejudice whereby AEM agreed to pay $6.2 million to resolve all business tax-related liabilities outstanding through September 2014. The order of dismissal will become effective upon approval of the Chancery Court.

We are a party to other 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

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2014, AEH was committed to purchase 100.5 Bcf within one year, 15.9 Bcf within one to three years and 0.8 Bcf after three years under indexed contracts. AEH is committed to purchase 9.5 Bcf within one year and 0.8 Bcf within one to three years under fixed price contracts with prices ranging from $3.75 to $6.36 per Mcf. Purchases under these contracts totaled $621.1 million and $327.8 million for the three months ended March 31, 2014 and 2013 and $971.3 million and $617.3 million for the six months ended March 31, 2014 and 2013.

Our natural gas distribution divisions 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 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, 2013. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2014.

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 March 31, 2014, rate cases were in progress in our Kansas, Kentucky, Virginia and West Texas service areas, annual rate filing mechanisms were in progress in Louisiana and Mid-Tex and infrastructure program filings were in progress in Mid-Tex and Atmos Pipeline–Texas. These regulatory proceedings are discussed in further detail below in Management’s Discussion and Analysis — Recent Ratemaking Developments.

8. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. During the six months ended March 31, 2014 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2013-2014 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 32 percent, or 24.6 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

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

Nonregulated Commodity Risk Management Activities

Our nonregulated operations aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To provide these services, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 49 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in asset optimization activities in our nonregulated segment.

Our nonregulated operations also 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.

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 March 31, 2014, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, at 3.129% and 3.37%, which we designated as cash flow hedges at the time the agreements were executed. In April and May 2014, we entered into forward starting interest rate swaps to effectively fix the Treasury yield component associated with $250 million of the anticipated issuance of $450 million unsecured senior notes in fiscal 2019 at 3.95%, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps are being recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. As of March 31, 2014, the remaining amortization periods for the settled Treasury locks extend through fiscal 2043.

Quantitative Disclosures Related to Financial Instruments

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

As of March 31, 2014, 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 March 31, 2014, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated	
		Quantity (MMcf)		
Commodity contracts	Fair Value	—	(5,770	)
	Cash Flow	—	21,795	
	Not designated	8,428	45,975	
		8,428	62,000	

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 March 31, 2014 and September 30, 2013. 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	Natural Gas Distribution Assets	Natural Gas Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
March 31, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$11,398	$(6,849)
Interest rate contracts	Other current assets / Other current liabilities	54,093	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	557	(944)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	30,665	—	—	—
Total		84,758	—	11,955	(7,793)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	4,653	—	48,402	(56,065)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	34,017	(24,720)
Total		4,653	—	82,419	(80,785)
Gross Financial Instruments		89,411	—	94,374	(88,578)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(85,464)	85,464
Net Financial Instruments		89,411	—	8,910	(3,114)
Cash collateral		—	—	7,940	3,114
Net Assets/Liabilities from Risk Management Activities		$89,411	$—	$16,850	$—

	Balance Sheet Location	Natural Gas Distribution Assets	Natural Gas Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2013					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$9,094	$(12,173)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	416	(1,639)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	107,512	—	—	—
Total		107,512	—	9,510	(13,812)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	1,837	(1,543)	65,388	(70,876)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	1,842	—	40,982	(45,892)
Total		3,679	(1,543)	106,370	(116,768)
Gross Financial Instruments		111,191	(1,543)	115,880	(130,580)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(115,875)	115,875
Net Financial Instruments		111,191	(1,543)	5	(14,705)
Cash collateral		—	—	10,124	14,705
Net Assets/Liabilities from Risk Management Activities		$111,191	$(1,543)	$10,129	$—

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2014 and 2013 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(3.7) million and $1.7 million. For the six months ended March 31, 2014 and 2013, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $1.4 million and $17.8 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2014 and 2013 is presented below.

	Three Months Ended March 31 2014	2013
	(In thousands)	
Commodity contracts	$3,587	$(17,846)
Fair value adjustment for natural gas inventory designated as the hedged item	(7,450)	19,586

Total (increase) decrease in purchased gas cost	$(3,863)	$1,740
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(579)	$1,458
Timing ineffectiveness	(3,284)	282
	$(3,863)	$1,740

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	Six Months Ended March 31	
	2014	2013
	(In thousands)	
Commodity contracts	$(4,974)	$(10,532)
Fair value adjustment for natural gas inventory designated as the hedged item	6,329	28,405
Total decrease in purchased gas cost	$1,355	$17,873
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(1,199)	$1,218
Timing ineffectiveness	2,554	16,655
	$1,355	$17,873

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 six months ended March 31, 2014 and 2013 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 March 31, 2014		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Gain reclassified from AOCI for effective portion of commodity contracts	$—	$7,184	$7,184
Gain arising from ineffective portion of commodity contracts	—	142	142
Total impact on purchased gas cost	—	7,326	7,326
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$(1,057)	$7,326	$6,269

	Three Months Ended March 31, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(5,199)	$(5,199)
Loss arising from ineffective portion of commodity contracts	—	(83)	(83)
Total impact on purchased gas cost	—	(5,282)	(5,282)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(873)	—	(873)

Total Impact from Cash Flow Hedges	$(873)	$(5,282)	$(6,155)

	Six Months Ended March 31, 2014		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Gain reclassified from AOCI for effective portion of commodity contracts	$—	$4,574	$4,574
Gain arising from ineffective portion of commodity contracts	—	24	24
Total impact on purchased gas cost	—	4,598	4,598
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(2,115)	—	(2,115)
Total Impact from Cash Flow Hedges	$(2,115)	$4,598	$2,483

	Six Months Ended March 31, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(10,359)	$(10,359)
Loss arising from ineffective portion of commodity contracts	—	(102)	(102)
Total impact on purchased gas cost	—	(10,461)	(10,461)
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,375)	—	(1,375)
Total Impact from Cash Flow Hedges	$(1,375)	$(10,461)	$(11,836)

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 six months ended March 31, 2014 and 2013. 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 March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$(27,718)	$22,955	$(14,448)	$34,900
Forward commodity contracts	5,483	5,666	11,709	2,153
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	671	554	1,343	873
Forward commodity contracts	(4,382)	3,172	(2,790)	6,320
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$(25,946)	$32,347	$(4,186)	$44,246

(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 accumulated other comprehensive income (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 gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2014. 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	$(1,830)	$4,682	$2,852
Thereafter	(27,191)	(239)	(27,430)
Total[1]	$(29,021)	$4,443	$(24,578)

(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 March 31, 2014 and 2013 was an increase (decrease) in gross profit of $(9.3) million and $6.8 million. For the six months ended March 31, 2014 and 2013 gross profit increased (decreased) by $(10.1) million and $6.7 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

9. Accumulated Other Comprehensive Income

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale securities, interest rate agreement cash flow hedges and commodity contract cash flow hedges. Deferred gains (losses) for our available-for-sale securities and commodity contract cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as they are amortized. The following 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.

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2013	$5,448	$37,906	$(4,476)	$38,878
Other comprehensive income before reclassifications	2,369	(14,448)	11,709	(370)
Amounts reclassified from accumulated other comprehensive income	(227)	1,343	(2,790)	(1,674)
Net current-period other comprehensive income	2,142	(13,105)	8,919	(2,044)
March 31, 2014	$7,590	$24,801	$4,443	$36,834

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total

	(In thousands)			
September 30, 2012	$5,661	$(44,273)	$(8,995)	$(47,607)
Other comprehensive income before reclassifications	1,135	34,900	2,153	38,188
Amounts reclassified from accumulated other comprehensive income	(1,708)	873	6,320	5,485
Net current-period other comprehensive income	(573)	35,773	8,473	43,673
March 31, 2013	$5,088	$(8,500)	$(522)	$(3,934)

The following tables detail reclassifications out of AOCI for the three and six months ended March 31, 2014 and 2013. Amounts in parentheses below indicate decreases to net income in the statement of income.

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2014 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$358	Operation and maintenance expense
	358	Total before tax
	(131)	Tax expense
	$227	Net of tax
Cash flow hedges		
Interest rate agreements	$(1,057)	Interest charges
Commodity contracts	7,184	Purchased gas cost
	6,127	Total before tax
	(2,416)	Tax expense
	$3,711	Net of tax
Total reclassifications	$3,938	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2013 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$2,689	Operation and maintenance expense
	2,689	Total before tax
	(981)	Tax expense
	$1,708	Net of tax
Cash flow hedges		
Interest rate agreements	$(873)	Interest charges
Commodity contracts	(5,201)	Purchased gas cost
	(6,074)	Total before tax
	2,348	Tax benefit
	$(3,726)	Net of tax
Total reclassifications	$(2,018)	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2014 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
Available-for-sale securities	$358		Operation and maintenance expense
	358		Total before tax
	(131	)	Tax expense
	$227		Net of tax
Cash flow hedges			
Interest rate agreements	$(2,115	)	Interest charges
Commodity contracts	4,574		Purchased gas cost
	2,459		Total before tax
	(1,012	)	Tax expense
	$1,447		Net of tax
Total reclassifications	$1,674		Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2013 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
Available-for-sale securities	$2,689		Operation and maintenance expense
	2,689		Total before tax
	(981	)	Tax expense
	$1,708		Net of tax
Cash flow hedges			
Interest rate agreements	$(1,375	)	Interest charges
Commodity contracts	(10,361	)	Purchased gas cost
	(11,736	)	Total before tax
	4,543		Tax benefit
	$(7,193	)	Net of tax
Total reclassifications	$(5,485	)	Net of tax

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, 2013. During the six months ended March 31, 2014, 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, 2013.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. 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 March 31, 2014 and September 30, 2013. 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]	March 31, 2014
	(In thousands)				
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$89,411	$—	$—	$89,411
Nonregulated segment	89	94,285	—	(77,524)	16,850
Total financial instruments	89	183,696	—	(77,524)	106,261
Hedged portion of gas stored underground	23,570	—	—	—	23,570
Available-for-sale securities					
Money market funds	—	2,904	—	—	2,904
Registered investment companies	44,263	—	—	—	44,263
Bonds	—	28,503	—	—	28,503
Total available-for-sale securities	44,263	31,407	—	—	75,670
Total assets	$67,922	$215,103	$—	$(77,524)	$205,501
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$—	$—	$—	$—
Nonregulated segment	1,297	87,281	—	(88,578)	—
Total liabilities	$1,297	$87,281	$—	$(88,578)	$—

	Quoted Prices in Active Markets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2013
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$111,191	$—	$—	$111,191
Nonregulated segment	745	115,135	—	(105,751)	10,129
Total financial instruments	745	226,326	—	(105,751)	121,320
Hedged portion of gas stored underground	44,758	—	—	—	44,758
Available-for-sale securities					
Money market funds	—	4,428	—	—	4,428
Registered investment companies	40,094	—	—	—	40,094
Bonds	—	28,160	—	—	28,160
Total available-for-sale securities	40,094	32,588	—	—	72,682
Total assets	$85,597	$258,914	$—	$(105,751)	$238,760
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$1,543	$—	$—	$1,543
Nonregulated segment	158	130,422	—	(130,580)	—
Total liabilities	$158	$131,965	$—	$(130,580)	$1,543

(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 March 31, 2014, we had $11.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $3.1 million was used to offset current risk management liabilities under master netting arrangements and the remaining $8.0 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2013 we had $24.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $14.7 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $10.1 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 March 31, 2014				
Domestic equity mutual funds	$27,226	$10,052	$—	$37,278
Foreign equity mutual funds	5,118	1,867	—	6,985
Bonds	28,320	191	(8)	28,503
Money market funds	2,904	—	—	2,904
	$63,568	$12,110	$(8)	$75,670
As of September 30, 2013				
Domestic equity mutual funds	$27,043	$7,476	$(23)	$34,496
Foreign equity mutual funds	4,536	1,062	—	5,598
Bonds	28,016	168	(24)	28,160
Money market funds	4,428	—	—	4,428
	$64,023	$8,706	$(47)	$72,682

At March 31, 2014 and September 30, 2013, our available-for-sale securities included $47.2 million and $44.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2014, we maintained investments in bonds that have contractual maturity dates ranging from April 2014 through July 2017. During the six months ended March 31, 2013, we recognized a gain of $2.7 million on the sale of certain assets in the rabbi trusts.

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 March 31, 2014 and September 30, 2013:

	March 31, 2014	September 30, 2013
	(In thousands)	
Carrying Amount	$2,460,000	$2,460,000
Fair Value	$2,739,091	$2,676,487

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, 2013. During the six months ended March 31, 2014, there were no material changes in our concentration of credit risk.

12. Discontinued Operations

On April 1, 2013, we completed the sale of substantially all of our natural gas distribution assets and certain related nonregulated assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million. In connection with the sale, we recognized a net of tax gain of $5.3 million.

For the three and six months ended March 31, 2013, net income from discontinued operations includes the operating results of our Georgia operations. As required under generally accepted accounting principles, the operating results from our discontinued Georgia operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The table below sets forth statement of income data related to discontinued operations. At March 31, 2014 and September 30, 2013 we did not have any assets or liabilities held for sale.

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Operating revenues	$—	$21,678	$—	$37,962
Purchased gas cost	—	12,497	—	21,464
Gross profit	—	9,181	—	16,498
Operating expenses	—	3,038	—	5,858
Operating income	—	6,143	—	10,640
Other nonoperating income	—	200	—	548
Income from discontinued operations before income taxes	—	6,343	—	11,188
Income tax expense	—	2,258	—	3,986
Net income from discontinued operations	$—	$4,085	$—	$7,202

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 March 31, 2014, the related condensed consolidated statements of income and comprehensive income for the three and six-month periods ended March 31, 2014 and 2013, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2014 and 2013. 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, 2013, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 13, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2013, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP
Dallas, Texas
May 7, 2014

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, 2013.

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 markets to satisfy our liquidity requirements; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; the impact of adverse economic conditions on our customers; the effects of inflation and changes in the availability and price of natural gas; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in Texas; increased competition from energy suppliers and alternative forms of energy; adverse weather conditions; the capital-intensive nature of our gas distribution business; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the risks of accidents and additional operating costs associating with distributing, transporting and storing natural gas; 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 transportation 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 natural gas distribution divisions, which at March 31, 2014 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 transportation and storage services to certain of our natural gas distribution divisions and to third parties.

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

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

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

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, 2013 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 six months ended March 31, 2014.

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 are seeking to achieve positive rate outcomes that benefit both our customers and the Company.

Consolidated income from continuing operations for the six months ended March 31, 2014 increased 16 percent period over period as a result of positive rate outcomes combined with increased gross profit associated with weather that was 25 percent colder than the prior-year period. Combined rate increases received in our regulated segments increased gross profit by $29.4 million. As of March 31, 2014, we had completed seven regulatory proceedings in our regulated segments resulting in an $18.2 million increase in annual operating income and had nine ratemaking efforts in progress seeking $124.1 million of additional annual operating income.

Our consolidated results were also favorably impacted by the significantly colder than normal weather experienced during the first six months of our fiscal year. Regulated gross profit increased $18.9 million due to increased customer consumption in our natural gas distribution segment and increased throughput and related margins in our regulated transportation segment associated with colder weather. The colder than normal weather also increased market demand for natural gas, which drove higher price volatility, particularly during our second fiscal quarter. As a result, realized gross margin in our nonregulated operations increased $22.6 million period over period from trading gains primarily captured during the second fiscal quarter.

During the first six months of fiscal 2014, our capital expenditures were $359.0 million, which primarily represents investments to improve the safety and reliability of our distribution and transportation systems. We expect our capital expenditures to range between $830 million and $850 million for fiscal 2014, and we plan to fund our growth through the use of operating cash flows and debt and equity securities, while maintaining a balanced capital structure.

On February 18, 2014, we completed the sale of 9,200,000 shares of common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares, under our shelf registration statement, generating net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

Our debt-to-capitalization ratio as of March 31, 2014 was 44 percent and our liquidity remained strong with over $1 billion of capacity from our short-term facilities. In October 2014, our $500 million Unsecured 4.95% Senior Notes will mature. We plan to issue new senior unsecured 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 3.129%. On January 30, 2014, Moody's upgraded our senior unsecured debt rating to A2 from Baa1 and our commercial paper rating to P-1 from P-2.

Finally, as a result of the continued contribution and stability of our regulated earnings, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 5.7 percent in the first quarter of fiscal 2014.

Consolidated Results

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Operating revenues	$1,964,322	$1,308,996	$3,219,470	$2,343,151
Gross profit	496,277	432,751	885,234	795,113
Operating expenses	246,197	222,573	464,434	430,013
Operating income	250,080	210,178	420,800	365,100
Miscellaneous income (expense)	(1,516)	1,712	(3,648)	2,410
Interest charges	31,601	33,331	63,716	63,853
Income from continuing operations before income taxes	216,963	178,559	353,436	303,657
Income tax expense	83,596	66,219	133,053	113,969
Income from continuing operations	133,367	112,340	220,383	189,688
Income from discontinued operations, net of tax	—	4,085	—	7,202
Net income	$133,367	$116,425	$220,383	$196,890
Diluted net income per share from continuing operations	$1.38	$1.23	$2.34	$2.07
Diluted net income per share from discontinued operations	—	0.04	—	0.08
Diluted net income per share	$1.38	$1.27	$2.34	$2.15

Our consolidated net income during the three and six month periods ended March 31, 2014 and 2013 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$88,743	$86,190	$2,553
Regulated transmission and storage segment	24,109	16,530	7,579
Nonregulated segment	20,515	9,620	10,895
Net income from continuing operations	133,367	112,340	21,027
Net income from discontinued operations	—	4,085	(4,085)
Net income	$133,367	$116,425	$16,942

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$151,500	$139,283	$12,217
Regulated transmission and storage segment	43,555	32,635	10,920
Nonregulated segment	25,328	17,770	7,558
Net income from continuing operations	220,383	189,688	30,695
Net income from discontinued operations	—	7,202	(7,202)
Net income	$220,383	$196,890	$23,493

Regulated operations contributed 85 percent and 89 percent to our consolidated net income for the three and six months ended March 31, 2014. 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 March 31		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$112,852	$102,720	$10,132
Nonregulated operations	20,515	9,620	10,895
Net income from continuing operations	133,367	112,340	21,027
Net income from discontinued operations	—	4,085	(4,085)
Net income	$133,367	$116,425	$16,942
Diluted EPS from continuing regulated operations	$1.17	$1.12	$0.05
Diluted EPS from nonregulated operations	0.21	0.11	0.10
Diluted EPS from continuing operations	1.38	1.23	0.15
Diluted EPS from discontinued operations	—	0.04	(0.04)
Consolidated diluted EPS	$1.38	$1.27	$0.11

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$195,055	171,918	$23,137
Nonregulated operations	25,328	17,770	7,558
Net income from continuing operations	220,383	189,688	30,695
Net income from discontinued operations	—	7,202	(7,202)
Net income	$220,383	$196,890	$23,493
Diluted EPS from continuing regulated operations	$2.07	$1.87	$0.20
Diluted EPS from nonregulated operations	0.27	0.20	0.07
Diluted EPS from continuing operations	2.34	2.07	0.27
Diluted EPS from discontinued operations	—	0.08	(0.08)
Consolidated diluted EPS	$2.34	$2.15	$0.19

Natural Gas Distribution Segment

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

Our ability to earn our authorized rates 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 natural gas 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 natural gas 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 does include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the 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 March 31, 2014 compared with Three Months Ended March 31, 2013

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31			
	2014	2013	Change	
	(In thousands, unless otherwise noted)			
Gross profit	$385,188	$347,006	$38,182	
Operating expenses	217,402	186,567	30,835	
Operating income	167,786	160,439	7,347	
Miscellaneous income	97	2,591	(2,494	)
Interest charges	22,828	25,664	(2,836	)
Income from continuing operations before income taxes	145,055	137,366	7,689	
Income tax expense	56,312	51,176	5,136	
Income from continuing operations	88,743	86,190	2,553	
Income from discontinued operations, net of tax	—	4,085	(4,085	)
Net income	$88,743	$90,275	$(1,532	)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	151,083	120,123	30,960	
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	40,404	36,540	3,864	
Consolidated natural gas distribution throughput from continuing operations — MMcf	191,487	156,663	34,824	
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	2,674	(2,674	)
Total consolidated natural gas distribution throughput — MMcf	191,487	159,337	32,150	
	$0.48	$0.47	$0.01	

Consolidated natural gas distribution average transportation revenue per Mcf			
Consolidated natural gas distribution average cost of gas per Mcf sold	$6.00	$4.67	$1.33

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Income from continuing operations for our natural gas distribution segment increased three percent, primarily due to a $38.2 million increase in gross profit, partially offset by a $30.8 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $13.2 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky and Louisiana service areas.
- a $4.9 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our West Texas, Kentucky/Mid-States and Mississippi Divisions.
- a $2.1 million increase in service order revenue.
- a $12.9 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $10.3 million increase in the related tax expense.

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 increased levels and timing of incentive compensation expense resulting from improved operating results, increased labor costs primarily associated with increased standby and overtime costs and lower labor capitalization rates as employees incurred more time compared to the prior year period to ensure our distribution system was safe and reliable during the colder than normal weather.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended March 31, 2014 and 2013. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Mid-Tex	$67,805	$59,713	$8,092
Kentucky/Mid-States	29,422	24,497	4,925
Louisiana	25,992	24,004	1,988
West Texas	15,764	15,008	756
Mississippi	20,559	19,825	734
Colorado-Kansas	16,603	16,677	(74)
Other	(8,359)	715	(9,074)
Total	$167,786	$160,439	$7,347

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Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013
Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$684,359	$626,637	$57,722
Operating expenses	393,700	357,114	36,586
Operating income	290,659	269,523	21,136
Miscellaneous income (expense)	(374)	2,460	(2,834)
Interest charges	46,153	49,227	(3,074)
Income from continuing operations before income taxes	244,132	222,756	21,376
Income tax expense	92,632	83,473	9,159
Income from continuing operations	151,500	139,283	12,217
Income from discontinued operations, net of tax	—	7,202	(7,202)
Net income	$151,500	$146,485	$5,015
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	249,361	198,876	50,485
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	72,611	69,429	3,182
Consolidated natural gas distribution throughput from continuing operations — MMcf	321,972	268,305	53,667
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	4,731	(4,731)
Total consolidated natural gas distribution throughput — MMcf	321,972	273,036	48,936
Consolidated natural gas distribution average transportation revenue per Mcf	$0.48	$0.46	$0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$5.82	$4.77	$1.05

Income from continuing operations for our natural gas distribution segment increased nine percent, primarily due to a $57.7 million increase in gross profit, partially offset by a $36.6 million increase in operating expenses. The year to date increase in gross profit primarily reflects:

- a $15.9 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our Mid-Tex, West Texas, Colorado-Kansas and Kentucky/Mid-State Divisions.
- a $15.3 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky, Louisiana and Tennessee service areas.
- a $17.8 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $14.3 million increase in the related tax expense.

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 increased levels and timing of incentive compensation expense resulting from improved operating results, increased labor costs primarily associated with increased standby and overtime costs and lower labor capitalization rates as employees incurred more time compared to the prior year period to ensure our distribution system was safe and reliable during the colder than normal weather.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the six months ended March 31, 2014 and 2013. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Mid-Tex	$124,909	$105,290	$19,619
Kentucky/Mid-States	47,519	40,202	7,317
Louisiana	43,418	40,889	2,529
West Texas	23,806	24,586	(780)
Mississippi	32,977	31,438	1,539
Colorado-Kansas	25,416	25,421	(5)
Other	(7,386)	1,697	(9,083)
Total	$290,659	$269,523	$21,136

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 six months of fiscal 2014, we completed seven regulatory proceedings, resulting in an $18.2 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$4,353
Annual rate filing mechanisms	12,497
Rate case filings	1,609
Other rate activity	(226)
	$18,233

Additionally, the following ratemaking efforts seeking $78.5 million in annual operating income were in progress as of March 31, 2014:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case	Kansas	$7,005
Kentucky/Mid-States	Rate Case[(1)]	Kentucky	13,133
Kentucky/Mid-States	Rate Case	Virginia	2,128
Louisiana	Rate Stabilization Clause[(2)]	Trans LA	550
Mid-Tex	Dallas Annual Rate Review	Dallas	7,934
Mid-Tex	Rate Review Mechanism	Mid-Tex Cities	34,874
Mid-Tex	GRIP	Mid-Tex Environs	881
West Texas	Rate Case[(3)]	West Texas	12,032
			$78,537

(1) The Kentucky rate case request of $13.1 million includes $2.5 million related to the Kentucky pipeline replacement program (PRP). Effective October 1, 2013, the $2.5 million increase associated with the PRP was included in rates. The ultimate resolution of the rate case will result in all current PRP charges rolling into base rates. The Kentucky commission issued a final order on April 2, 2014 authorizing an increase of $5.8 million.

(2)

The Trans LA rate stabilization clause operating income increase of $0.6 million was implemented on April 1, 2014.

(3) The West Texas rate case operating income increase of $8.4 million was implemented on April 1, 2014. The West Texas Cities portion of the division also agreed to reestablish the annual rate review mechanism process. The cities of Amarillo, Channing, Dalhart and Lubbock agreed to annual GRIP filings.

Infrastructure Programs

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. As of March 31, 2014, we had infrastructure programs approved in Texas, Kansas, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the six months ended March 31, 2014.

Division	Period End	Incremental Net Utility Plant Investment (In thousands)	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Infrastructure Programs:				
Kentucky/Mid-States - Kentucky	09/2014	$17,488	$2,493	10/01/2013
Kentucky/Mid-States - Virginia	09/2014	1,587	210	10/01/2013
Mid-Tex - Environs[1]	12/2012	1,473,948	768	10/01/2013
Colorado-Kansas - Kansas	09/2013	9,323	882	02/01/2014
Total 2014 Infrastructure Programs		$1,502,346	$4,353	

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

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As of March 31, 2014 we had annual rate filing mechanisms in our Louisiana and Mississippi service areas and in our Texas divisions. These mechanisms are referred to as the Dallas annual rate review (DARR) and rate review mechanism (RRM) in our Mid-Tex and West Texas Divisions, stable rate filings in the Mississippi Division and rate stabilization clause in the Louisiana Division. The following annual rate filing mechanisms were completed during the six months ended March 31, 2014.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
		(In thousands)		
2014 Filings:				
Mid-Tex	Mid-Tex Cities	12/31/2012	$12,497	11/01/2013
Total 2014 Filings			$12,497	

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 to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate cases that were completed during the six months ended March 31, 2014.

Division	State	Increase in Annual Operating Income	Effective Date
	(In thousands)		
2014 Rate Case Filings:			

Colorado-Kansas	Colorado	$ 1,609	03/01/2014
Total 2014 Rate Case Filings		$ 1,609	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2014.

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

[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 Transmission and Storage Segment

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

Our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains. The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

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

Three Months Ended March 31, 2014 compared with Three Months Ended March 31, 2013
Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$50,761	$42,947	$7,814
Third-party transportation	18,885	14,769	4,116
Storage and park and lend services	1,429	1,562	(133)
Other	2,540	2,570	(30)
Gross profit	73,615	61,848	11,767
Operating expenses	25,519	28,357	(2,838)
Operating income	48,096	33,491	14,605
Miscellaneous expense	(1,081)	(99)	(982)
Interest charges	9,155	7,857	1,298
Income before income taxes	37,860	25,535	12,325
Income tax expense	13,751	9,005	4,746
Net income	$24,109	$16,530	$7,579
Gross pipeline transportation volumes — MMcf	210,610	179,021	31,589
Consolidated pipeline transportation volumes — MMcf	115,830	105,099	10,731

Net income for our regulated transmission and storage segment increased 46 percent, primarily due to an $11.8 million increase in gross profit, combined with a $2.8 million decrease in operating expenses. The increase in gross profit primarily reflects a $7.3 million increase in rates from the approved 2013 GRIP filing coupled with a $1.4 million increase associated with higher throughput and basis spreads driven by colder weather.

Operating expenses decreased $2.8 million primarily due to a $6.7 million refund received as a result of the completion of a state use tax audit. The refund was partially offset by increased depreciation expense associated with increased capital investments and employee-related expenses.

On May 6, 2014, a GRIP filing was approved by the RRC for $45.6 million of additional annual operating income.

Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$100,505	$83,732	$16,773
Third-party transportation	36,044	29,318	6,726
Storage and park and lend services	3,250	3,072	178
Other	5,157	6,407	(1,250)
Gross profit	144,956	122,529	22,427
Operating expenses	57,268	57,016	252
Operating income	87,688	65,513	22,175
Miscellaneous expense	(2,262)	(226)	(2,036)
Interest charges	18,112	14,728	3,384
Income before income taxes	67,314	50,559	16,755
Income tax expense	23,759	17,924	5,835
Net income	$43,555	$32,635	$10,920
Gross pipeline transportation volumes — MMcf	399,786	340,505	59,281
Consolidated pipeline transportation volumes — MMcf	234,604	213,842	20,762

Net income for our regulated transmission and storage segment increased 33 percent, primarily due to a $22.4 million increase in gross profit. The increase in gross profit primarily reflects a $14.1 million increase in rates from the approved 2013 GRIP filing coupled with a $3.0 million increase associated with higher throughput and basis spreads driven by colder weather.

The APT rate case approved by the RRC on April 18, 2011 contained an annual adjustment mechanism, approved for a
three-year pilot program, that adjusted regulated rates up or down by 75 percent of the difference between APT's non-regulated
annual revenue and a pre-defined base credit. The annual adjustment mechanism expired on June 30, 2013. On January 1, 2014, the RRC approved the extension of the annual adjustment mechanism retroactive to July 1, 2013, which will stay in place until the completion of APT's next rate case. As a result of this decision, we recognized a $1.8 million increase in gross profit for the application of the annual adjustment mechanism, for the period July 1, 2013 to September 30, 2013.

Operating expenses increased $0.3 million primarily due to increased depreciation expense associated with increased capital investments and employee-related expenses, partially offset by the aforementioned state use tax refund.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, for the fiscal year ended September 30, 2013, 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 natural gas distribution operations in Louisiana and Kentucky. These demand fees are subject to regulatory oversight and are renewed periodically.

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of buying, selling and delivering natural gas to offer more competitive pricing to those customers.

Natural gas prices can influence:

- The demand for natural gas. Higher prices may cause customers to conserve or use alternative energy sources. Conversely, lower prices could cause customers such as electric power generators to switch from alternative energy sources to natural gas.

- Collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment.
- The level of borrowings under our credit facilities, which affects the level of interest expense recognized by this segment.

Natural gas price volatility can also influence our nonregulated business in the following ways:

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Increased or decreased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Our nonregulated segment manages its exposure to natural gas commodity price risk through a combination of physical storage and financial instruments. Therefore, results for this segment include unrealized gains or losses on its net physical gas position and the related financial instruments used to manage commodity price risk. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

Three Months Ended March 31, 2014 compared with Three Months Ended March 31, 2013

Financial and operating highlights for our nonregulated segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$12,449	$15,264	$(2,815)
Storage and transportation services	3,677	3,596	81
Other	19,829	2,806	17,023
Total realized margins	35,955	21,666	14,289
Unrealized margins	1,634	2,641	(1,007)
Gross profit	37,589	24,307	13,282
Operating expenses	3,391	8,060	(4,669)
Operating income	34,198	16,247	17,951
Miscellaneous income (expense)	443	(91)	534
Interest charges	593	498	95
Income before income taxes	34,048	15,658	18,390
Income tax expense	13,533	6,038	7,495
Net income	$20,515	$9,620	$10,895
Gross nonregulated delivered gas sales volumes — MMcf	139,753	109,723	30,030
Consolidated nonregulated delivered gas sales volumes — MMcf	119,967	97,732	22,235
Net physical position (Bcf)	1.9	20.8	(18.9)

The $13.3 million quarter-over-quarter increase in gross profit reflected a $14.3 million increase in realized margins, offset by a $1.0 million decrease in unrealized margins. The $14.3 million increase in realized margins reflects:

- A $17.0 million increase in realized margins due to the acceleration of physical withdrawals into the second quarter to capture gross profit margin during periods of increased natural gas price volatility caused by strong market demand as a result of significantly colder weather during the current quarter compared with the prior-year quarter.

- A $2.8 million decrease in gas delivery and related services margins. Consolidated sales volumes increased twenty-three percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. The increases in volume were offset by lower gas delivery per-unit margins which decreased from 14 cents per Mcf in the prior-year quarter to 9 cents, which reflects losses incurred to meet peaking requirements for certain customers during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Unrealized margins decreased $1.0 million primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.
Operating expenses decreased $4.7 million, primarily due to lower legal expense related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 7 to the financial statements.

Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013
Financial and operating highlights for our nonregulated segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$24,912	$25,334	$(422)
Storage and transportation services	7,212	7,117	95
Other	11,827	(11,304)	23,131
Total realized margins	43,951	21,147	22,804
Unrealized margins	12,204	25,619	(13,415)
Gross profit	56,155	46,766	9,389
Operating expenses	13,702	16,705	(3,003)
Operating income	42,453	30,061	12,392
Miscellaneous income	767	1,576	(809)
Interest charges	1,230	1,295	(65)
Income before income taxes	41,990	30,342	11,648
Income tax expense	16,662	12,572	4,090
Net income	$25,328	$17,770	$7,558
Gross nonregulated delivered gas sales volumes — MMcf	247,332	208,732	38,600
Consolidated nonregulated delivered gas sales volumes — MMcf	212,604	182,450	30,154
Net physical position (Bcf)	1.9	20.8	(18.9)

Net income for our nonregulated segment increased 43 percent from the prior year due to higher gross profit and decreased operating expenses.

The $9.4 million period-over-period increase in gross profit reflected a $22.8 million increase in realized margins, offset by a $13.4 million decrease in unrealized margins. The $22.8 million increase in realized margins reflects:

- A $23.1 million increase in other realized margins due to the aforementioned storage optimization gains earned during the second quarter. In contrast, losses were incurred from storage optimization activities in the prior year largely due to unfavorable changes in market prices relative to the execution strategy in place at that time.
- A $0.4 million decrease in gas delivery and related services margins. Consolidated sales volumes increased seventeen percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. Additionally, gas delivery per-unit margins decreased from 12 cents per Mcf in the prior-year period to 10 cents per Mcf due primarily to losses incurred during the second quarter to meet peaking requirements for certain customers during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Unrealized margins decreased $13.4 million primarily due to the period-over-period timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $3.0 million, primarily due to lower legal expense related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 7 to the financial statements.

Liquidity and Capital Resources

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

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

We plan 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 have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

As of March 31, 2014, $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2014, September 30, 2013 and March 31, 2013:

	March 31, 2014			September 30, 2013			March 31, 2013		
	(In thousands, except percentages)								
Short-term debt	$—	—	%	$367,984	6.8	%	$232,998	4.5	%
Long-term debt[1]	2,455,829	44.0	%	2,455,671	45.4	%	2,455,514	46.9	%
Shareholders' equity	3,124,761	56.0	%	2,580,409	47.8	%	2,543,470	48.6	%
Total	$5,580,590	100.0	%	$5,404,064	100.0	%	$5,231,982	100.0	%

[1] In October 2014, $500 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 3.129%.

Total debt as a percentage of total capitalization, including short-term debt, was 44 percent at March 31, 2014, 52.2 percent at September 30, 2013 and 51.4 percent at March 31, 2013.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, 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 six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$490,981	$376,341	$114,640
Investing activities	(363,913)	(392,817)	28,904
Financing activities	(56,527)	17,784	(74,311)
Change in cash and cash equivalents	70,541	1,308	69,233
Cash and cash equivalents at beginning of period	66,199	64,239	1,960
Cash and cash equivalents at end of period	$136,740	$65,547	$71,193

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 natural gas 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 six months ended March 31, 2014, we generated cash flow of $491.0 million from operating activities compared with $376.3 million for the six months ended March 31, 2013. The $114.6 million increase in operating cash flows primarily reflects higher operating results from colder weather and rate increases combined with the timing of customer collections and vendor payments.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects in our regulated operations, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our regulatory strategy, we focus our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline–Texas Division have rate tariffs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the six months ended March 31, 2014, capital expenditures were $359.0 million, compared with $389.1 million in the prior-year period. The period-over-period decrease primarily reflects:

- A $19.1 million decrease in capital spending in our regulated transmission and storage segment associated with the completion of the Line WX expansion project, partially offset by increased cathodic protection spending.
- A $10.3 million decrease in capital spending in our natural gas distribution segment due to the timing of spending under our infrastructure replacement programs and the absence of spending related to our new customer information system, which was completed in the prior year.

Cash flows from financing activities

For the six months ended March 31, 2014, our financing activities used $56.5 million of cash compared with $17.8 million generated in the prior-year period. The decrease is primarily due to timing between short-term debt borrowings and repayments during the current year partially offset by proceeds from the equity offering completed in February 2014 compared with proceeds generated from the issuance of long-term debt in the prior-year period.

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The following table summarizes our share issuances for the six months ended March 31, 2014 and 2013.

	Six Months Ended March 31	
	2014	2013
Shares issued:		
1998 Long-Term Incentive Plan	479,521	385,020
Outside Directors Stock-for-Fee Plan	922	1,125
February 2014 Offering	9,200,000	—
Total shares issued	9,680,443	386,145

The year-over-year increase in the number of shares issued primarily reflects the equity offering completed in February 2014 as well as a higher number of performance-based awards issued in the current year as actual performance exceeded the target. For the six months ended March 31, 2014 and 2013, we canceled and retired 142,829 and 87,931 shares attributable to federal withholdings on equity awards.

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 $950.0 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1 billion of working capital funding. As of March 31, 2014, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1,012.8 million.

Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of March 31, 2014, all three ratings 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-
Commercial paper	A-2	P-1	F-2

On January 30, 2014, Moody's upgraded our senior unsecured debt rating to A2 from Baa1 and our commercial paper rating to P-1 from P-2.

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 March 31, 2014. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 7 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2014.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated 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 natural gas distribution segment's financial instruments for the three and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$134,776	$(64,197)	$109,648	$(76,260)
Contracts realized/settled	6,868	(306)	5,197	2,529
Fair value of new contracts	347	683	866	1,013
Other changes in value	(52,580)	103,946	(26,300)	112,844
Fair value of contracts at end of period	$89,411	$40,126	$89,411	$40,126

The fair value of our natural gas distribution segment's financial instruments at March 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2014				
	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	$58,746	$30,665	$—	$—	$89,411
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$58,746	$30,665	$—	$—	$89,411

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The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$(5,093)	$(1,562)	$(14,700)	$(15,123)
Contracts realized/settled	4,635	(492)	14,578	12,244
Fair value of new contracts	—	—	—	—
Other changes in value	6,254	(1,965)	5,918	(1,140)
Fair value of contracts at end of period	5,796	(4,019)	5,796	(4,019)
Netting of cash collateral	11,054	11,971	11,054	11,971
Cash collateral and fair value of contracts at period end	$16,850	$7,952	$16,850	$7,952

The fair value of our nonregulated segment's financial instruments at March 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2014				
	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	$(3,114)	$9,068	$(158)	$—	$5,796
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(3,114)	$9,068	$(158)	$—	$5,796

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2014 and 2013, our total net periodic pension and other benefits costs were $37.2 million and $37.8 million. A substantial portion of those costs relating to our natural gas 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 2014 costs were determined using a September 30, 2013 measurement date. As of September 30, 2013, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2012, the measurement date for our fiscal 2013 net periodic cost. Therefore, we increased the discount rate used to measure our fiscal 2014 net periodic cost from 4.04 percent to 4.95 percent. However, we decreased the expected return on plan assets from 7.75 percent to 7.25 percent in the determination of our fiscal 2014 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2014 net periodic pension cost to decrease by less than five percent.

The amounts with which we fund our defined benefit plans are determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plans when the funding requirements are determined on January 1 of each year. For the six months ended March 31, 2014 we contributed $9.1 million to our defined benefit plans. Based upon the most recent evaluation, we anticipate contributing a total of between $10 million and $35 million to our defined benefit plans in fiscal 2014. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. For the six months ended March 31, 2014 we contributed $11.6 million to our postretirement medical plans. We anticipate contributing a total of between $20 million and $25 million to these plans during fiscal 2014.

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 natural gas distribution, regulated transmission and storage and nonregulated segments for the three and six month periods ended March 31, 2014 and 2013.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
METERS IN SERVICE, end of period				
Residential	2,777,135	2,816,734	2,777,135	2,816,734
Commercial	250,144	256,955	250,144	256,955
Industrial	1,495	2,127	1,495	2,127
Public authority and other	8,797	10,268	8,797	10,268
Total meters	3,037,571	3,086,084	3,037,571	3,086,084
INVENTORY STORAGE BALANCE — Bcf[1]	22.6	28.3	22.6	28.3
SALES VOLUMES — MMcf[2]				
Gas sales volumes				
Residential	95,913	74,929	156,329	121,252
Commercial	45,521	36,465	76,935	61,721
Industrial	5,805	4,928	9,824	9,483
Public authority and other	3,844	3,801	6,273	6,420
Total gas sales volumes	151,083	120,123	249,361	198,876
Transportation volumes	44,319	39,925	79,743	73,947
Total throughput	195,402	160,048	329,104	272,823
OPERATING REVENUES (000's)[2]				
Gas sales revenues				
Residential	$843,385	$589,180	$1,388,802	$1,011,901
Commercial	358,907	244,338	594,330	429,269
Industrial	30,797	24,300	54,545	45,756
Public authority and other	27,694	22,470	44,143	38,150
Total gas sales revenues	1,260,783	880,288	2,081,820	1,525,076
Transportation revenues	20,939	17,792	37,756	33,233
Other gas revenues	9,238	7,096	15,249	13,654
Total operating revenues	$1,290,960	$905,176	$2,134,825	$1,571,963
Average transportation revenue per Mcf[1]	$0.47	$0.45	$0.47	$0.46
Average cost of gas per Mcf sold[1]	$6.00	$4.67	$5.82	$4.77

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
Meters in service, end of period	—	64,089	—	64,089
Sales volumes — MMcf				
Total gas sales volumes	—	2,069	—	3,611
Transportation volumes	—	605	—	1,120
Total throughput	—	2,674	—	4,731
Operating revenues (000’s)	$—	$21,678	$—	$37,962

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
CUSTOMERS, end of period				
Industrial	748	772	748	772
Municipal	130	124	130	124
Other	564	437	564	437
Total	1,442	1,333	1,442	1,333
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	9.7	25.2	9.7	25.2
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[2]	210,610	179,021	399,786	340,505
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[2]	139,753	109,723	247,332	208,732
OPERATING REVENUES (000’s)[2]				
Regulated transmission and storage	$73,615	$61,848	$144,956	$122,529
Nonregulated	757,683	428,948	1,205,404	828,842
Total operating revenues	$831,298	$490,796	$1,350,360	$951,371

Notes to preceding tables:

(1) Statistics are shown on a consolidated basis.

(2) 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, 2013. During the six months ended March 31, 2014, 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 March 31, 2014 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 second quarter of the fiscal year ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

During the six months ended March 31, 2014, except as noted in Note 7 to the unaudited condensed consolidated financial statements, 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, 2013. 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: May 7, 2014

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
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.