ATMOS ENERGY CORP
Form 10-Q
August 05, 2009

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes o No o

* The registrant has not yet been phased into the interactive data requirements.

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 o Non-Accelerated Filer o Smaller Reporting Company o
(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 o No þ

Number of shares outstanding of each of the issuer s classes of common stock, as of July 31, 2009.

Class	Shares Outstanding
No Par Value	92,272,478

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
FSP	FASB Staff Position
GRIP	Gas Reliability Infrastructure Program
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody s	Moody s Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor s Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
WNA	Weather Normalization Adjustment

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PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2009 (Unaudited)	September 30, 2008
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 5,963,098	$ 5,730,156
Less accumulated depreciation and amortization	1,623,734	1,593,297
Net property, plant and equipment	4,339,364	4,136,859
Current assets		
Cash and cash equivalents	125,735	46,717
Accounts receivable, net	241,582	477,151
Gas stored underground	317,275	576,617
Other current assets	111,420	184,619
Total current assets	796,012	1,285,104
Goodwill and intangible assets	738,615	739,086
Deferred charges and other assets	222,039	225,650
	$ 6,096,030	$ 6,386,699
CAPITALIZATION AND LIABILITIES		
Shareholders equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2009 92,234,134 shares; September 30, 2008 90,814,683 shares	$ 461	$ 454
Additional paid-in capital	1,779,184	1,744,384
Retained earnings	451,856	343,601
Accumulated other comprehensive loss	(39,981)	(35,947)
Shareholders equity	2,191,520	2,052,492
Long-term debt	2,169,395	2,119,792
Total capitalization	4,360,915	4,172,284
Current liabilities		

Accounts payable and accrued liabilities	221,968	395,388
Other current liabilities	422,200	460,372
Short-term debt		350,542
Current maturities of long-term debt	131	785
Total current liabilities	644,299	1,207,087
Deferred income taxes	510,901	441,302
Regulatory cost of removal obligation	322,529	298,645
Deferred credits and other liabilities	257,386	267,381
	$ 6,096,030	$ 6,386,699

See accompanying notes to condensed consolidated financial statements

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ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 386,985	$ 676,639
Regulated transmission and storage segment	49,345	46,286
Natural gas marketing segment	453,504	1,189,722
Pipeline, storage and other segment	8,226	3,880
Intersegment eliminations	(117,285)	(277,382)
	780,775	1,639,145
Purchased gas cost		
Natural gas distribution segment	195,303	476,711
Regulated transmission and storage segment		
Natural gas marketing segment	438,482	1,192,353
Pipeline, storage and other segment	4,212	706
Intersegment eliminations	(116,862)	(276,847)
	521,135	1,392,923
Gross profit	259,640	246,222
Operating expenses		
Operation and maintenance	110,895	117,822
Depreciation and amortization	54,181	50,356
Taxes, other than income	47,577	57,335
Asset impairments	3,304	
Total operating expenses	215,957	225,513
Operating income	43,683	20,709
Miscellaneous income	1,219	1,600
Interest charges	41,511	33,470
Income (loss) before income taxes	3,391	(11,161)
Income tax expense (benefit)	1,427	(4,573)
Net income (loss)	$ 1,964	$ (6,588)
Basic net income (loss) per share	$ 0.02	$ (0.07)

Diluted net income (loss) per share	$	0.02	$	(0.07)
Cash dividends per share	$	0.330	$	0.325
Weighted average shares outstanding:				
Basic		91,338		89,648
Diluted		92,002		89,648

See accompanying notes to condensed consolidated financial statements

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ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 2,673,373	$ 3,126,672
Regulated transmission and storage segment	163,261	142,772
Natural gas marketing segment	1,949,657	3,159,092
Pipeline, storage and other segment	36,946	20,629
Intersegment eliminations	(504,724)	(668,525)
	4,318,513	5,780,640
Purchased gas cost		
Natural gas distribution segment	1,816,227	2,296,020
Regulated transmission and storage segment		
Natural gas marketing segment	1,881,068	3,099,428
Pipeline, storage and other segment	9,771	1,773
Intersegment eliminations	(503,456)	(666,835)
	3,203,610	4,730,386
Gross profit	1,114,903	1,050,254
Operating expenses		
Operation and maintenance	365,312	359,064
Depreciation and amortization	160,757	147,659
Taxes, other than income	150,028	153,170
Asset impairments	5,382	
Total operating expenses	681,479	659,893
Operating income	433,424	390,361
Miscellaneous income (expense)	(647)	2,974
Interest charges	116,035	103,803
Income before income taxes	316,742	289,532
Income tax expense	109,812	110,783
Net income	$ 206,930	$ 178,749
Basic net income per share	$ 2.28	$ 2.00

Diluted net income per share	$	2.26	$	1.99
Cash dividends per share	$	0.990	$	0.975
Weighted average shares outstanding:				
Basic		90,940		89,281
Diluted		91,590		89,937

See accompanying notes to condensed consolidated financial statements

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ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 206,930	$ 178,749
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	160,757	147,659
Charged to other accounts	60	106
Deferred income taxes	62,658	77,864
Other	23,009	12,767
Net assets/liabilities from risk management activities	53,711	(78,524)
Net change in operating assets and liabilities	317,469	78,760
Net cash provided by operating activities	824,594	417,381
Cash Flows From Investing Activities		
Capital expenditures	(342,326)	(312,878)
Other, net	(6,094)	(4,303)
Net cash used in investing activities	(348,420)	(317,181)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(366,449)	(35,721)
Net proceeds from debt offering	445,623	
Settlement of Treasury lock agreement	1,938	
Repayment of long-term debt	(407,287)	(9,945)
Cash dividends paid	(90,909)	(87,821)
Issuance of common stock	19,928	19,063
Net cash used in financing activities	(397,156)	(114,424)
Net increase (decrease) in cash and cash equivalents	79,018	(14,224)
Cash and cash equivalents at beginning of period	46,717	60,725
Cash and cash equivalents at end of period	$ 125,735	$ 46,501

See accompanying notes to condensed consolidated financial statements

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2009

1. Nature of Business

Atmos Energy Corporation (Atmos Energy or the Company) and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[1]
Atmos Energy Kentucky/Mid-States Division	Georgia[1], Illinois[1], Iowa[1], Kentucky, Missouri[1], Tennessee, Virginia[1]
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

[1] Denotes states where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our natural gas distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Our regulated transmission and storage business consists of the regulated operations of our Atmos Pipeline Texas Division. The Atmos Pipeline Texas Division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary to the pipeline industry including parking arrangements, lending services and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas.

Our natural gas marketing operations are conducted through Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility

systems and industrial natural gas customers, primarily in the Southeast and Midwest and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments.

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is used primarily to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of June 30, 2009.

2. Unaudited Interim Financial Information

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, 2008. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2009 are not indicative of our results of operations for the full 2009 fiscal year, which ends September 30, 2009.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008 and there have been no changes to those policies. However, during the nine months ended June 30, 2009, we recognized a non-recurring $7.8 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

During the second quarter of fiscal 2009, we updated the tax rates used to record deferred taxes. The one-time tax benefit resulted in a favorable impact to net income of $11.3 million.

Additionally, during the second quarter of fiscal 2009, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Effective October 1, 2008, the Company adopted Statement of Financial Accounting Standards (SFAS) 157, *Fair Value Measurements*, the measurement date requirements of SFAS 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement*

No. 115 and SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133.* Effective April 1, 2009, the Company adopted FASB Staff Position (FSP) FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* and SFAS 165, *Subsequent Events.* Except for the adoption of these accounting pronouncements, which are further discussed below, there were no significant changes to our accounting policies during the nine months ended June 30, 2009.

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosure on fair value measurements required under other accounting pronouncements but does not change existing guidance as to whether or not an instrument is carried at fair value. The adoption of this standard did not materially impact our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 4.

Effective October 1, 2008, the Company adopted the measurement date requirements of SFAS 158 using the remeasurement approach. Under this approach, the Company remeasured our projected benefit obligation, fair value of plan assets and our fiscal 2009 net periodic cost. In accordance with the transition rules of SFAS 158, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million during the first quarter of fiscal 2009.

SFAS 159 permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The adoption of this standard did not impact our financial position, results of operations or cash flows.

SFAS 161 expands the disclosure requirements for derivative instruments and hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; the accounting for derivative instruments and related hedged items; and how derivative instruments and related hedged items affect an entity s financial position, results of operations and cash flows. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard did not have an impact on our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 3.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. The disclosure is required for interim and annual reports. The disclosure requirements of this FSP are presented in Note 4.

In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities. In addition, FSP FAS 115-2 and FAS 124-2 expands the existing disclosure requirements about debt and equity securities to interim reporting as well as provides new disclosure requirements. We adopted the provisions of this FSP for the quarter ended June 30, 2009. The adoption of FSP FAS 115-2 and FAS 124-2 did not impact our financial position, results of operations or cash flows. The disclosure requirements of this FSP are presented in Note 7.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*. This FSP

provides further guidance for estimating fair value in accordance with SFAS 157 when there has been a significant decrease in market activity for a financial asset and also identifies circumstances that indicate a transaction is not orderly. The adoption of this FSP did not impact our financial position, results of operations or cash flows.

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before the date the financial statements are issued or available to be issued. SFAS 165 requires companies to reflect in their financial statements the effects of subsequent events that provide additional evidence about conditions at the balance-sheet date. Subsequent events that provide evidence about conditions that arose after the balance-sheet date should be disclosed if the financial statements would otherwise be misleading. We adopted the provisions of SFAS 165 for quarter ended June 30, 2009. We have evaluated subsequent events from the balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation,* when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2009 and September 30, 2008 included the following:

	June 30, 2009	September 30, 2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 88,472	$ 100,563
Merger and integration costs, net	7,268	7,586
Deferred gas costs	24,355	55,103
Environmental costs	685	980
Rate case costs	7,640	12,885
Deferred franchise fees	577	651
Deferred income taxes, net	343	343
Other	7,085	8,120
	$ 136,425	$ 186,231
Regulatory liabilities:		
Deferred gas costs	$ 97,495	$ 76,979
Regulatory cost of removal obligation	336,737	317,273
Other	5,429	5,639

	$ 439,661	$ 399,891

Currently, our 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. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and nine-month periods ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Net income (loss)	$ 1,964	$ (6,588)	$ 206,930	$ 178,749
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $1,282 and $531 for the three months ended June 30, 2009 and 2008 and of $(2,477) and $(140) for the nine months ended June 30, 2009 and 2008	2,086	866	(4,209)	(231)
Other than temporary impairment of investments, net of tax expense of $1,222 and $2,012 for the three and nine months ended June 30, 2009	2,082		3,370	
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $320 and $482 for the three months ended June 30, 2009 and 2008 and $2,155 and $1,446 for the nine months ended June 30, 2009 and 2008	543	787	3,184	2,361
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $16,582 and $1,850 for the three months ended June 30, 2009 and 2008 and $(4,759) and $9,047 for the nine months ended June 30, 2009 and 2008	25,936	3,018	(6,379)	14,761
Comprehensive income (loss)	$ 32,611	$ (1,917)	$ 202,896	$ 195,640

Accumulated other comprehensive loss, net of tax, as of June 30, 2009 and September 30, 2008 consisted of the following unrealized gains (losses):

	June 30, 2009	September 30, 2008
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 71	$ 910
Treasury lock agreements	(7,920)	(11,104)

Cash flow hedges	(32,132)	(25,753)
	$ (39,981)	$ (35,947)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage 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 financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

Regulated Commodity Risk Management Activities

In our natural gas distribution segment, our customers are exposed to the effect 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. If the regulatory authority does not establish this level, we typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2008-2009 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 27 percent, or 24.3 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas 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 SFAS 71. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas

supplies, transportation and markets to which we have access. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of these activities, our nonregulated operations are 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. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 43 months. The effective portion of the unrealized gains and losses arising from the use of cash flow hedges is recorded as a component of accumulated other comprehensive income (AOCI) on the balance sheet. Amounts associated with cash flow hedges recognized in the income statement include (i) the amount of unrealized gain or loss that has been reclassified from AOCI when the hedged volumes are sold and (ii) the amount of ineffectiveness associated with these hedges in the period the ineffectiveness arises.

We use financial instruments, designated as fair value hedges, to hedge the exposure to changes in the fair value of our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments. Therefore, gains and losses arising from these financial instruments should offset the changes in the fair value of the hedged item to the extent the hedging relationship is effective. Ineffectiveness is recognized in the income statement in the period the ineffectiveness arises.

Our natural gas marketing segment also uses 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 pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2009, AEH had net open positions (including existing storage) of 0.3 Bcf.

Interest Rate Risk Management Activities

In March 2009, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with our $450 million 8.50% senior notes (the Senior Notes Offering), which was completed on March 26, 2009. The Senior Notes Offering is discussed in Note 5. We designated this Treasury

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lock as a cash flow hedge of an anticipated transaction. This Treasury lock was settled on March 23, 2009 with the receipt of $1.9 million from the counterparty due to an increase in the 10 year Treasury rates between inception of the Treasury lock and settlement. Because the Treasury lock was effective, the net $1.2 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 10 year life of the senior notes.

In prior years, we similarly managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts of these Treasury locks will be recognized through fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

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

As of June 30, 2009, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2009, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value		(22,905)	(2,050)
	Cash Flow		31,993	(4,118)
	Not designated	21,702	84,606	(51)
		21,702	93,694	(6,219)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2009 and September 30, 2008. As required by SFAS 161, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $20.6 million and $56.6 million of cash held on deposit in margin accounts as of June 30, 2009 and September 30, 2008 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic

exposure. Additionally, the amounts below will

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
June 30, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$	$ 71,992	$ 71,992
Noncurrent commodity contracts	Deferred charges and other assets		6,383	6,383
Liability Financial Instruments				
Current commodity contracts	Other current liabilities		(71,878)	(71,878)
Noncurrent commodity contracts	Deferred credits and other liabilities		(1,150)	(1,150)
Total			5,347	5,347
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	1,233	28,887	30,120
Noncurrent commodity contracts	Deferred charges and other assets		6,381	6,381
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,945)	(20,428)	(43,373)
Noncurrent commodity contracts	Deferred credits and other liabilities	(316)	(1,743)	(2,059)
Total		(22,028)	13,097	(8,931)
Total Financial Instruments		$ (22,028)	$ 18,444	$ (3,584)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	

September 30, 2008:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$	$ 101,191	$ 101,191
Noncurrent commodity contracts	Deferred charges and other assets		4,984	4,984
Liability Financial Instruments				
Current commodity contracts	Other current liabilities		(89,397)	(89,397)
Noncurrent commodity contracts	Deferred credits and other liabilities		(206)	(206)
Total			16,572	16,572
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets		20,010	20,010
Noncurrent commodity contracts	Deferred charges and other assets		1,093	1,093
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(58,566)	(20,145)	(78,711)
Noncurrent commodity contracts	Deferred credits and other liabilities	(5,111)	(988)	(6,099)
Total		(63,677)	(30)	(63,707)
Total Financial Instruments		$ (63,677)	$ 16,542	$ (47,135)

(1) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three and nine months ended June 30, 2009 and 2008.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments 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 June 30, 2009 and 2008 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $0.2 million and $(4.7) million. For the nine months ended June 30, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.7 million and $40.6 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2009 and 2008 is presented below.

	Three Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 2,710	$ 1,390	$ 4,100
Fair value adjustment for natural gas inventory designated as the hedged item	3,929	(741)	3,188
Total impact on revenue	$ 6,639	$ 649	$ 7,288
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 678	$	$ 678
Timing ineffectiveness	5,961	649	6,610
	$ 6,639	$ 649	$ 7,288

	Three Months Ended June 30, 2008	
	Natural Gas	Pipeline, Storage and

	Marketing	Other	Consolidated
		(In thousands)	
Commodity contracts	$ (50,391)	$ (2,049)	$ (52,440)
Fair value adjustment for natural gas inventory designated as the hedged item	46,765	1,431	48,196
Total impact on revenue	$ (3,626)	$ (618)	$ (4,244)
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (2,402)	$	$ (2,402)
Timing ineffectiveness	(1,224)	(618)	(1,842)
	$ (3,626)	$ (618)	$ (4,244)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)		
Commodity contracts	$ 48,263	$ 7,435	$ 55,698
Fair value adjustment for natural gas inventory designated as the hedged item	(26,493)	(2,731)	(29,224)
Total impact on revenue	$ 21,770	$ 4,704	$ 26,474
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,958	$	$ 4,958
Timing ineffectiveness	16,812	4,704	21,516
	$ 21,770	$ 4,704	$ 26,474

	Nine Months Ended June 30, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)		
Commodity contracts	$ (66,612)	$ (662)	$ (67,274)
Fair value adjustment for natural gas inventory designated as the hedged item	104,288	3,841	108,129
Total impact on revenue	$ 37,676	$ 3,179	$ 40,855
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (1,185)	$	$ (1,185)
Timing ineffectiveness	38,861	3,179	42,040
	$ 37,676	$ 3,179	$ 40,855

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 revenue.

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Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2009 and 2008 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$	$ (36,669)	$ (2,503)	$ (39,172)
Loss arising from ineffective portion of commodity contracts		(7,120)		(7,120)
Total impact on revenue		(43,789)	(2,503)	(46,292)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(863)			(863)
Total Impact from Cash Flow Hedges	$ (863)	$ (43,789)	$ (2,503)	$ (47,155)

	Three Months Ended June 30, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain reclassified from AOCI into revenue for effective portion of commodity contracts	$	$ 10,040	$ 57	$ 10,097
Loss arising from ineffective portion of commodity contracts		(406)		(406)
Total impact on revenue		9,634	57	9,691
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)			(1,269)
Total Impact from Cash Flow Hedges	$ (1,269)	$ 9,634	$ 57	$ 8,422

	Nine Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$	$ (142,986)	$ 25,213	$ (117,773)
Loss arising from ineffective portion of commodity contracts		(1,748)		(1,748)
Total impact on revenue		(144,734)	25,213	(119,521)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(3,401)			(3,401)
Total Impact from Cash Flow Hedges	$ (3,401)	$ (144,734)	$ 25,213	$ (122,922)

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	Nine Months Ended June 30, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)		
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$	$ (3,744)	$ 9,334	$ 5,590
Loss arising from ineffective portion of commodity contracts		(281)		(281)
Total impact on revenue		(4,025)	9,334	5,309
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(3,807)			(3,807)
Total Impact from Cash Flow Hedges	$ (3,807)	$ (4,025)	$ 9,334	$ 1,502

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2009 and 2008. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
		(In thousands)		
Increase (decrease) in fair value:				
Treasury lock agreements	$	$	$ 1,221	$
Forward commodity contracts	2,041	9,278	(78,220)	18,227
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	543	787	1,963	2,361
Forward commodity contracts	23,895	(6,260)	71,841	(3,466)
Total other comprehensive income (loss) from hedging, net of tax[1]	$ 26,479	$ 3,805	$ (3,195)	$ 17,122

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$ (1,687)	$ (30,303)	$ (31,990)
Thereafter	(6,233)	(1,829)	(8,062)
Total[1]	$ (7,920)	$ (32,132)	$ (40,052)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

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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 and nine months ended June 30, 2009 and 2008 is presented below. 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 to 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.

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Natural gas marketing commodity contracts	$ 6,167	$ (12,786)	$ 12,928	$ (26,580)
Pipeline, storage and other commodity contracts	(6,853)	2,594	(6,753)	1,705
Total impact on revenue	$ (686)	$ (10,192)	$ 6,175	$ (24,875)

4. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) and expands disclosures about fair value measurements. This Statement does not require any new fair value measurements; rather it provides guidance on how to perform fair value measurements as required or permitted under previous accounting pronouncements.

We prospectively adopted the provisions of SFAS 157 on October 1, 2008 for most of the financial assets and liabilities recorded on our balance sheet at fair value. Adoption of this statement for these assets and liabilities did not have a material impact on our financial position, results of operations or cash flows.

In February 2008, the FASB issued FSP FAS 157-2, *Effective Date of FASB Statement No. 157,* which provided a one-year deferral of SFAS 157 for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. Under this partial deferral, SFAS 157 will not be effective until October 1, 2009 for fair value measurements for the following:

Asset retirement obligations

Most nonfinancial assets and liabilities that may be acquired in a business combination

Impairment analyses performed for nonfinancial assets

We believe the adoption of SFAS 157 for the reporting of these nonfinancial assets and liabilities will not have a material impact on our financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*, which clarified the application of SFAS 157 in inactive markets. This FSP did not impact our financial position, results of operations or cash flows.

SFAS 157 also applies to the valuation of our pension and post-retirement plan assets. The adoption of this standard did not affect these valuations because SFAS 157 specifically excluded pension and post-retirement assets from its prescribed disclosure provisions. Accordingly, these plan assets are not included in the tabular disclosures below. However, in December 2008, the FASB issued FSP FAS 132(R)-1 *Employers*

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Disclosures about Postretirement Benefit Plan Assets, which will, among other things, require disclosure about fair value measurements similar to those required by SFAS 157. This FSP will impact our annual disclosure requirements beginning in fiscal 2010.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*. This FSP provides further guidance for estimating fair value in accordance with SFAS 157 when there has been a significant decrease in market activity for a financial asset and also identifies circumstances that indicate a transaction is not orderly. The adoption of this FSP did not impact our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. We have adopted the disclosure requirements of this FSP, which are presented below.

Determining Fair Value

SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under SFAS 157. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. A continued tightening of the credit markets could cause more of our counterparties to fail to perform. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to

unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities.

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Level 2 Pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable.

Level 3 Generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Currently, we have no assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009. As required under SFAS 157, 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)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[1]	June 30, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$	$ 1,233	$	$	$ 1,233
Natural gas marketing segment	40,494	73,149		(73,722)	39,921
Total financial instruments	40,494	74,382		(73,722)	41,154
Hedged portion of gas stored underground					
Natural gas marketing segment	79,604				79,604
Pipeline, storage and other segment[2]	7,023				7,023
Total gas stored underground	86,627				86,627
Available-for-sale securities	38,856				38,856
Total assets	$ 165,977	$ 74,382	$	$ (73,722)	$ 166,637

Liabilities:					
Financial instruments					
Natural gas distribution segment	$	$ 23,261	$	$	$ 23,261
Natural gas marketing segment	72,410	22,789		(94,336)	863
Total liabilities	$ 72,410	$ 46,050	$	$ (94,336)	$ 24,124

(1) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and FSP FIN 39-1. In addition, as of June 30, 2009, we had $20.6 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $0.1 million was used to offset financial instruments in a liability position. The remaining $20.5 million has been reflected as a financial instrument asset.

(2) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

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Other Fair Value Measures

In addition to the financial instruments above, we have several nonfinancial assets and liabilities subject to fair value measures. These assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable, debt, asset retirement obligations and pension and post-retirement plan assets. As noted above, fair value disclosures for asset retirement obligations and pension and post-retirement plan assets are not currently effective for us. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities. The fair value of our debt is determined using a discounted cash flow analysis based upon borrowing rates currently available to us, the remaining average maturities and our credit rating. The following table presents the carrying value and fair value of our debt as of June 30, 2009:

	June 30, 2009 (In thousands)
Carrying Amount	$ 2,172,893
Fair Value	$ 2,068,388

The fair value as of June 30, 2009 was calculated utilizing discount rates ranging from 3.5 percent to 7.2 percent, remaining average maturities ranging from one to 26 years, and a credit adjustment of 2.9 percent.

5. Debt

Long-term debt

Long-term debt at June 30, 2009 and September 30, 2008 consisted of the following:

	June 30, 2009	September 30, 2008
	(In thousands)	
Unsecured 4.00% Senior Notes, redeemed April 2009	$	$ 400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 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	
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 2010	10,000	10,000

Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Other term notes due in installments through 2013	590	1,309
Total long-term debt	2,172,893	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(3,367)	(3,035)
Current maturities	(131)	(785)
	$ 2,169,395	$ 2,119,792

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On March 26, 2009, we closed our Senior Notes Offering. The effective interest rate on these notes is 8.69 percent, after giving effect to the settlement of the $450 million Treasury lock discussed in Note 3. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds were used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers needs could significantly affect our borrowing requirements. 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 $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding. At June 30, 2009, there was no short-term debt outstanding. At September 30, 2008, there was $350.5 million of short-term debt outstanding, comprised of $330.5 million outstanding under our bank credit facilities and $20.0 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed primarily through a $566.7 million commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year unsecured facility, expiring December 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company s credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At the time this credit facility was established, borrowings under this facility were limited to $600 million. However, in September 2008, the limit on borrowings was effectively reduced to $566.7 million after one lender with a 5.55% share of the commitments ceased funding under the facility. On March 30, 2009, the credit facility was amended to reflect this reduction. At June 30, 2009, there were no borrowings under this facility and $566.7 million was available.

The second facility is a $212.5 million unsecured 364-day facility expiring October 2009, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.25 percent to 2.50 percent, based on the Company s credit ratings. At June 30, 2009, there were no borrowings outstanding under this facility.

The third facility was an $18 million unsecured facility that bore interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility expired on March 31, 2009 and was replaced with a $25 million unsecured facility effective April 1, 2009 that bears interest at a daily negotiated rate. At June 30, 2009, there were no borrowings outstanding under this facility.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2009, our total-debt-to-

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total-capitalization ratio, as defined, was 52 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $200 million intercompany revolving credit facility with AEH. Through December 31, 2008, this facility bore interest at the one-month LIBOR rate plus 0.20 percent. In January 2009, this facility was replaced with a new $200 million 364 day-facility that bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There was $40.3 million outstanding under this facility at June 30, 2009.

Nonregulated Operations

On December 30, 2008, AEM and the participating banks amended and restated AEM s former uncommitted credit facility, primarily to convert the $580 million uncommitted demand credit facility to a 364-day $375 million committed revolving credit facility and extend it to December 29, 2009. Effective April 1, 2009, the borrowing base was increased to $450 million through the exercise of an accordion feature in the facility.

The amended facility also adds a swing line loan feature; adjusts the interest rate on borrowings as discussed below and increases the fees paid to reflect the facility s conversion to a committed facility and current credit market conditions. The swing line loan feature allows AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM s option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its prime rate or base rate for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a one-month interest period) as in effect from time to time; and (d) the cost of funds rate based on an average of interest rates reported by one or more of the lenders to the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a cost of funds rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At June 30, 2009, there were no borrowings outstanding under this credit facility. However, at June 30, 2009, AEM letters of credit totaling $24.0 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $100.6 million at June 30, 2009.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2009, AEM s ratio of total liabilities to tangible net worth, as defined, was 0.86 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at June 30, 2009, AEM s net working capital was $195.5 million and its tangible net worth was $210.5 million.

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To supplement borrowings under this facility, through December 31, 2008, AEM had a $200 million intercompany demand credit facility with AEH, which bore interest at the rate for AEM s offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM s committed credit facility. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM s offshore borrowings under its committed credit facility plus 0.75 percent. There were no borrowings outstanding under this facility at June 30, 2009.

Finally, through December 31, 2008, AEH had a $200 million intercompany demand credit facility with AEC, which bore interest at the rate for AEM s offshore borrowings under its committed credit facility plus 0.75 percent. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM s offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There were no borrowings outstanding under this facility at June 30, 2009.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006.

As of June 30, 2009, we had $450 million of availability remaining under the registration statement after completing our Senior Notes Offering. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

Debt Covenants

In addition to the financial covenants described above, our debt instruments contain various covenants that are usual and customary for debt instruments of these types.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, AEM s credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate.

Finally, AEM s credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody s rating of Baa2. We have no other triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any

transactions that would require us to issue equity, based on our credit rating or other triggering events.

We were in compliance with all of our debt covenants as of June 30, 2009. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

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6. Earnings Per Share

Basic and diluted earnings per share for the three and nine months ended June 30, 2009 and 2008 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Net income (loss)	$ 1,964	$ (6,588)	$ 206,930	$ 178,749
Denominator for basic income per share weighted average common shares	91,338	89,648	90,940	89,281
Effect of dilutive securities:				
Restricted and other shares	616		611	557
Stock options	48		39	99
Denominator for diluted income per share weighted average common shares	92,002	89,648	91,590	89,937
Income (loss) per share basic	$ 0.02	$ (0.07)	$ 2.28	$ 2.00
Income (loss) per share diluted	$ 0.02	$ (0.07)	$ 2.26	$ 1.99

There were approximately 33,000 and 132,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2009.

There were approximately 557,000 restricted and other shares and approximately 99,000 stock options that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2008 as their inclusion in the computation would be anti-dilutive. There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2008 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and nine months ended June 30, 2009 and 2008 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,703	$ 3,879	$ 2,946	$ 3,342
Interest cost	7,554	6,736	3,520	2,912
Expected return on assets	(6,238)	(6,311)	(573)	(715)
Amortization of transition asset			378	377
Amortization of prior service cost	(183)	(171)		
Amortization of actuarial loss	955	1,926		
Net periodic pension cost	$ 5,791	$ 6,059	$ 6,271	$ 5,916

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 11,109	$ 11,635	$ 8,838	$ 10,024
Interest cost	22,662	20,208	10,560	8,736
Expected return on assets	(18,714)	(18,932)	(1,719)	(2,145)
Amortization of transition asset			1,134	1,133
Amortization of prior service cost	(549)	(513)		
Amortization of actuarial loss	2,865	5,778		
Net periodic pension cost	$ 17,373	$ 18,176	$ 18,813	$ 17,748

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2009 and 2008 are as follows:

	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
Discount rate	7.57%	6.30%	7.57%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

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, 2009. In June 2009, we contributed $21 million in cash to our pension plans to achieve a desired level of funding while maximizing the tax deductibility of this payment.

We contributed $8.2 million to our other post-retirement benefit plans during the nine months ended June 30, 2009. We expect to contribute a total of approximately $11 million to these plans during fiscal 2009.

In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP amends the other-than-temporary impairment guidance for debt securities and expands the presentation and disclosure of other-than-temporary impairments on debt and equity securities in interim and annual financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities.

For our Supplemental Executive Benefit Plans, we own equity securities that are classified as available-for-sale securities. 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.

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Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of June 30, 2009:				
Domestic equity mutual funds	$ 25,824	$ 286	$	$ 26,110
Foreign equity mutual funds	4,047			4,047
Money market funds	8,699			8,699
	$ 38,570	$ 286	$	$ 38,856
As of September 30, 2008:				
Domestic equity mutual funds	$ 31,041	$ 1,625	$ (394)	$ 32,272
Foreign equity mutual funds	5,309	359		5,668
	$ 36,350	$ 1,984	$ (394)	$ 37,940

The following table presents interest and dividends on available-for-sale securities for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Interest	$ 8	$	$ 8	$
Dividends	184	190	1,607	2,032
Total interest and dividends	$ 192	$ 190	$ 1,615	$ 2,032

The following table presents realized gains and losses on available-for-sale securities for the three and nine months ended June 30, 2009 and 2008. The gross realized investment losses exclude losses from other-than-temporary impairment:

	Nine Months Ended

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Gross realized investment gains	$	$ 51	$	$ 97
Gross realized investment losses		(2)	(129)	(3)
Net realized gains (losses)	$	$ 49	$ (129)	$ 94

Due to the recent deterioration of the financial markets and the uncertainty of a full recovery of these investments given the current economic environment, we have recorded a $3.3 million and $5.4 million noncash charge to impair certain available-for-sale investments during the three and nine months ended June 30, 2009. As a result of these impairments, at June 30, 2009, we did not maintain any investments that are in an unrealized loss position.

8. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30,

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2008, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2009. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2009, AEM was committed to purchase 83.0 Bcf within one year and 25.4 Bcf within one to three years under indexed contracts. AEM is committed to purchase 2.9 Bcf within one year under fixed price contracts with prices ranging from $3.15 to $7.68 per Mcf. Purchases under these contracts totaled $256.0 million and $842.1 million for the three months ended June 30, 2009 and 2008 and $1,215.0 million and $2,274.4 million for the nine months ended June 30, 2009 and 2008.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in this service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2009 are as follows (in thousands):

2009	$ 20,256
2010	120,481
2011	5,658
2012	7,302
2013	7,711
Thereafter	2,614
	$ 164,022

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the Commission) in

connection with its investigation into possible violations of the Commission s posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission s rules. We have completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain transactions that could possibly be considered non-compliant, and we continue to fully

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cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of June 30, 2009, rate cases were in progress in our City of Dallas and Virginia service areas and annual rate filing mechanisms were in progress in our City of Dallas and Amarillo service areas. These regulatory proceedings are discussed in further detail in *Management s Discussion and Analysis Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. During the nine months ended June 30, 2009, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage business as well as other nonregulated businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers primarily in the Midwest and Southeast. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

We operate the Company through the following four 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 the Atmos Pipeline Texas Division.

The *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services.

The *pipeline, storage and other segment,* which includes our nonregulated natural gas transmission and storage 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, 2008. We evaluate performance based on net income or loss of the respective operating units.

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Income statements for the three and nine month periods ended June 30, 2009 and 2008 by segment are presented in the following tables:

	Three Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$ 386,774	$ 29,558	$ 358,458	$ 5,985	$	$ 780,775
Intersegment revenues	211	19,787	95,046	2,241	(117,285)	
	386,985	49,345	453,504	8,226	(117,285)	780,775
Purchased gas cost	195,303		438,482	4,212	(116,862)	521,135
Gross profit	191,682	49,345	15,022	4,014	(423)	259,640
Operating expenses						
Operation and maintenance	89,534	13,784	6,445	1,641	(509)	110,895
Depreciation and amortization	47,928	5,066	392	795		54,181
Taxes, other than income	44,014	2,569	628	366		47,577
Asset impairments	2,823	370	90	21		3,304
Total operating expenses	184,299	21,789	7,555	2,823	(509)	215,957
Operating income	7,383	27,556	7,467	1,191	86	43,683
Miscellaneous income	2,167	615	71	2,319	(3,953)	1,219
Interest charges	32,798	8,152	4,020	408	(3,867)	41,511
Income (loss) before income taxes	(23,248)	20,019	3,518	3,102		3,391
Income tax expense (benefit)	(8,307)	7,065	1,419	1,250		1,427
Net income (loss)	$ (14,941)	$ 12,954	$ 2,099	$ 1,852	$	$ 1,964
Capital expenditures	$ 86,861	$ 28,216	$ 82	$ 5,837	$	$ 120,996

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	Three Months Ended June 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$ 676,418	$ 27,321	$ 933,931	$ 1,475	$	$ 1,639,145
Intersegment revenues	221	18,965	255,791	2,405	(277,382)	
	676,639	46,286	1,189,722	3,880	(277,382)	1,639,145
Purchased gas cost	476,711		1,192,353	706	(276,847)	1,392,923
Gross profit	199,928	46,286	(2,631)	3,174	(535)	246,222
Operating expenses						
Operation and maintenance	95,853	17,042	4,433	1,115	(621)	117,822
Depreciation and amortization	44,737	4,860	381	378		50,356
Taxes, other than income	54,141	2,493	391	310		57,335
Total operating expenses	194,731	24,395	5,205	1,803	(621)	225,513
Operating income (loss)	5,197	21,891	(7,836)	1,371	86	20,709
Miscellaneous income	3,508	550	377	2,273	(5,108)	1,600
Interest charges	28,504	6,606	2,850	532	(5,022)	33,470
Income (loss) before income taxes	(19,799)	15,835	(10,309)	3,112		(11,161)
Income tax expense (benefit)	(7,421)	5,570	(3,995)	1,273		(4,573)
Net income (loss)	$ (12,378)	$ 10,265	$ (6,314)	$ 1,839	$	$ (6,588)
Capital expenditures	$ 92,856	$ 18,252	$ 132	$ 2,916	$	$ 114,156

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$ 2,672,742	$ 91,877	$ 1,524,438	$ 29,456	$	$ 4,318,513
Intersegment revenues	631	71,384	425,219	7,490	(504,724)	
	2,673,373	163,261	1,949,657	36,946	(504,724)	4,318,513
Purchased gas cost	1,816,227		1,881,068	9,771	(503,456)	3,203,610
Gross profit	857,146	163,261	68,589	27,175	(1,268)	1,114,903
Operating expenses						
Operation and maintenance	276,462	58,448	27,228	4,700	(1,526)	365,312
Depreciation and amortization	142,608	15,027	1,189	1,933		160,757
Taxes, other than income	139,861	7,929	1,667	571		150,028
Asset impairments	4,599	602	146	35		5,382
Total operating expenses	563,530	82,006	30,230	7,239	(1,526)	681,479
Operating income	293,616	81,255	38,359	19,936	258	433,424
Miscellaneous income (expense)	6,123	1,713	490	6,540	(15,513)	(647)
Interest charges	94,506	23,580	11,383	1,821	(15,255)	116,035
Income before income taxes	205,233	59,388	27,466	24,655		316,742
Income tax expense	68,465	19,308	11,444	10,595		109,812
Net income	$ 136,768	$ 40,080	$ 16,022	$ 14,060	$	$ 206,930
Capital expenditures	$ 260,482	$ 61,579	$ 199	$ 20,066	$	$ 342,326

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended June 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$ 3,126,083	$ 72,588	$ 2,568,643	$ 13,326	$	$ 5,780,640
Intersegment revenues	589	70,184	590,449	7,303	(668,525)	
	3,126,672	142,772	3,159,092	20,629	(668,525)	5,780,640
Purchased gas cost	2,296,020		3,099,428	1,773	(666,835)	4,730,386
Gross profit	830,652	142,772	59,664	18,856	(1,690)	1,050,254
Operating expenses						
Operation and maintenance	291,678	47,560	17,835	3,939	(1,948)	359,064
Depreciation and amortization	130,699	14,683	1,142	1,135		147,659
Taxes, other than income	142,063	6,322	3,798	987		153,170
Total operating expenses	564,440	68,565	22,775	6,061	(1,948)	659,893
Operating income	266,212	74,207	36,889	12,795	258	390,361
Miscellaneous income	7,654	933	1,775	6,243	(13,631)	2,974
Interest charges	88,802	20,453	6,166	1,755	(13,373)	103,803
Income before income taxes	185,064	54,687	32,498	17,283		289,532
Income tax expense	71,622	19,351	12,933	6,877		110,783
Net income	$ 113,442	$ 35,336	$ 19,565	$ 10,406	$	$ 178,749
Capital expenditures	$ 266,840	$ 40,334	$ 201	$ 5,503	$	$ 312,878

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Balance sheet information at June 30, 2009 and September 30, 2008 by segment is presented in the following tables:

	June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$ 3,625,656	$ 631,136	$ 7,232	$ 75,340	$	$ 4,339,364
Investment in subsidiaries	526,941		(2,096)		(524,845)	
Current assets						
Cash and cash equivalents	39,276		76,111	10,348		125,735
Assets from risk management activities	1,233		30,696	3,835	(4,510)	31,254
Other current assets	416,144	16,481	211,197	55,510	(60,309)	639,023
Intercompany receivables	507,278			146,140	(653,418)	
Total current assets	963,931	16,481	318,004	215,833	(718,237)	796,012
Intangible assets			1,617			1,617
Goodwill	569,920	132,367	24,282	10,429		736,998
Noncurrent assets from risk management activities			9,900			9,900
Deferred charges and other assets	181,945	9,959	1,045	19,190		212,139
	$ 5,868,393	$ 789,943	$ 359,984	$ 320,792	$ (1,243,082)	$ 6,096,030
CAPITALIZATION AND LIABILITIES						
Shareholders equity	$ 2,191,520	$ 170,224	$ 101,997	$ 254,720	$ (526,941)	$ 2,191,520
Long-term debt	2,168,937			458		2,169,395
Total capitalization	4,360,457	170,224	101,997	255,178	(526,941)	4,360,915
Current liabilities						
Current maturities of long-term debt				131		131
Short-term debt	40,340				(40,340)	
Liabilities from risk management activities	22,945		4,668	705	(4,510)	23,808

Other current liabilities	427,859	8,270	151,717	50,274	(17,760)	620,360
Intercompany payables		530,513	122,905		(653,418)	
Total current liabilities	491,144	538,783	279,290	51,110	(716,028)	644,299
Deferred income taxes	444,621	76,837	(21,955)	11,511	(113)	510,901
Noncurrent liabilities from risk management activities	316					316
Regulatory cost of removal obligation	322,529					322,529
Deferred credits and other liabilities	249,326	4,099	652	2,993		257,070
	$ 5,868,393	$ 789,943	$ 359,984	$ 320,792	$ (1,243,082)	$ 6,096,030

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ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	September 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$ 3,483,556	$ 585,160	$ 7,520	$ 60,623	$	$ 4,136,859
Investment in subsidiaries	463,158		(2,096)		(461,062)	
Current assets						
Cash and cash equivalents	30,878		9,120	6,719		46,717
Assets from risk management activities			69,008	20,239	(20,956)	68,291
Other current assets	774,933	18,396	411,648	56,791	(91,672)	1,170,096
Intercompany receivables	578,833			135,795	(714,628)	
Total current assets	1,384,644	18,396	489,776	219,544	(827,256)	1,285,104
Intangible assets			2,088			2,088
Goodwill	569,920	132,367	24,282	10,429		736,998
Noncurrent assets from risk management activities			5,473			5,473
Deferred charges and other assets	195,985	11,212	1,182	11,798		220,177
	$ 6,097,263	$ 747,135	$ 528,225	$ 302,394	$ (1,288,318)	$ 6,386,699
CAPITALIZATION AND LIABILITIES						
Shareholders equity	$ 2,052,492	$ 130,144	$ 114,559	$ 218,455	$ (463,158)	$ 2,052,492
Long-term debt	2,119,267			525		2,119,792
Total capitalization	4,171,759	130,144	114,559	218,980	(463,158)	4,172,284
Current liabilities						
Current maturities of long-term debt				785		785
Short-term debt	385,592		6,500		(41,550)	350,542
Liabilities from risk management activities	58,566		20,688	616	(20,956)	58,914
Other current liabilities	538,777	7,053	236,217	62,796	(47,997)	796,846
Intercompany payables		543,384	171,244		(714,628)	

Total current liabilities	982,935	550,437	434,649	64,197	(825,131)	1,207,087
Deferred income taxes	384,860	62,720	(21,936)	15,687	(29)	441,302
Noncurrent liabilities from risk management activities	5,111		258			5,369
Regulatory cost of removal obligation	298,645					298,645
Deferred credits and other liabilities	253,953	3,834	695	3,530		262,012
	$ 6,097,263	$ 747,135	$ 528,225	$ 302,394	$ (1,288,318)	$ 6,386,699

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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 as of June 30, 2009, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2009 and 2008, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2009 and 2008. 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 as of September 30, 2008, and the related consolidated statements of income, shareholders equity, and cash flows for the year then ended, not presented herein, and in our report dated November 18, 2008, 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, 2008, 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
August 5, 2009

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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, 2008.

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 , see 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, which are discussed in more detail in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of recent adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business; 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 3.2 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonregulated businesses, we primarily 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.

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We operate the Company through the following four 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 the Atmos Pipeline Texas Division,

the *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services and

the *pipeline, storage and other segment,* which is comprised of our nonregulated natural gas gathering, transmission and storage 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, 2008 and include the following:

Regulation

Revenue Recognition

Allowance for Doubtful Accounts

Derivatives and Hedging Activities

Impairment Assessments

Pension and Other Postretirement Plans

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2009.

RESULTS OF OPERATIONS

During the current fiscal year, several external factors have impacted Atmos Energy, including but not limited to adverse developments in the global and financial credit markets and the unfavorable impact of the economic recession.

The tightening of the credit markets has made it more difficult and more expensive for us to access the capital markets. However, during the fiscal year, we have undertaken several steps to improve our financial position. In March 2009, we successfully completed an offering of $450 million 8.5% senior notes, and used most of the proceeds in April 2009 to redeem $400 million of senior notes that were scheduled to mature in October 2009. Additionally, we enhanced our liquidity sources in various ways. In October 2008, we replaced our former $300 million 364-day committed credit facility with a new 364-day $212.5 million committed credit facility. Additionally, we converted AEM s former $580 million uncommitted credit facility to a 364-day $375 million committed credit facility. This facility was subsequently increased to $450 million in April 2009. Finally, in April 2009 we replaced an expiring $18 million unsecured committed credit facility

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with a $25 million unsecured committed credit facility. After entering into these new facilities, we currently have a total of approximately $1.3 billion available to us under four committed credit facilities. As a result of these developments and our continued successful financial performance, Standard & Poor s Corporation (S&P) upgraded our credit rating from BBB to BBB+ in December 2008 and Moody s Investors Service (Moody s) upgraded the credit rating on our senior long-term debt from Baa3 to Baa2 and our commercial paper from P-3 to P-2 in May 2009. These ratings upgrades should improve our ability to access the short-term capital markets to satisfy our liquidity requirements on more economical terms in the future.

Challenging economic times have also impacted most of our business segments. The impact of the economic downturn is most apparent in a general decline in throughput. Our natural gas distribution segment has experienced a year-over-year four percent decrease in consolidated throughput, primarily associated with lower residential, commercial and industrial consumption. Declines in the demand for natural gas as a result of idle production and plant closures have contributed to a seven percent year-over-year decrease in consolidated throughput in our regulated transmission and storage segment and a five percent year-over-year decrease in consolidated sales volumes in our natural gas marketing segment. However, recent improvements in rate design in our natural gas distribution segment and the ability to earn higher per-unit margins in our regulated transmission and storage and natural gas marketing segments has more than offset the decline in throughput and sales volumes. Additionally, reduced demand for natural gas has resulted in lower natural gas prices, which has contributed significantly to the increase in our operating cash flow from $417 million for the nine months ended June 30, 2008 to $825 million for the nine months ended June 30, 2009.

The seasonality of our distribution business typically results in a loss in our fiscal third quarter. However, we reported net income of $2.0 million, or $0.02 per diluted share for the three months ended June 30, 2009 compared with a net loss of $6.6 million, or $0.07 per diluted share in the prior-year quarter. The quarter-over-quarter improvement reflects higher gross profit in our regulated transmission and storage and natural gas marketing segments combined with lower consolidated operation and maintenance expense, which more than offset lower natural gas distribution margins and a $3.3 million charge to impair certain available-for-sale investments.

For the first nine months of fiscal 2009, net income increased 16 percent to $206.9 million, or $2.26 per diluted share. Regulated operations contributed 85 percent of our net income during this period with our nonregulated operations contributing the remaining 15 percent. Results for the nine months ended June 30, 2009 include the favorable impact of a one-time tax benefit of $11.3 million, or $0.12 per diluted share and the unfavorable impact of a $5.4 million charge, or $0.04 per diluted share, to impair certain available-for-sale investments. Additionally, results for the nine-month period ended June 30, 2009 reflect increased gross profit across all of our business segments, partially offset by higher depreciation expense, pipeline maintenance and employee costs and interest expense.

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands, except per share data)			
Operating revenues	$ 780,775	$ 1,639,145	$ 4,318,513	$ 5,780,640
Gross profit	259,640	246,222	1,114,903	1,050,254
Operating expenses	215,957	225,513	681,479	659,893
Operating income	43,683	20,709	433,424	390,361

Miscellaneous income (expense)	1,219	1,600	(647)	2,974
Interest charges	41,511	33,470	116,035	103,803
Income (loss) before income taxes	3,391	(11,161)	316,742	289,532
Income tax expense (benefit)	1,427	(4,573)	109,812	110,783
Net income (loss)	$ 1,964	$ (6,588)	$ 206,930	$ 178,749
Diluted net income (loss) per share	$ 0.02	$ (0.07)	$ 2.26	$ 1.99

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Our consolidated net income (loss) during the three and nine months ended June 30, 2009 and 2008 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$ (14,941)	$ (12,378)	$ (2,563)
Regulated transmission and storage segment	12,954	10,265	2,689
Natural gas marketing segment	2,099	(6,314)	8,413
Pipeline, storage and other segment	1,852	1,839	13
Net income (loss)	$ 1,964	$ (6,588)	$ 8,552

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$ 136,768	$ 113,442	$ 23,326
Regulated transmission and storage segment	40,080	35,336	4,744
Natural gas marketing segment	16,022	19,565	(3,543)
Pipeline, storage and other segment	14,060	10,406	3,654
Net income	$ 206,930	$ 178,749	$ 28,181

The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$ (1,987)	$ (2,113)	$ 126
Nonregulated operations	3,951	(4,475)	8,426
Consolidated net income (loss)	$ 1,964	$ (6,588)	$ 8,552
Diluted EPS from regulated operations	$ (0.02)	$ (0.02)	$
Diluted EPS from nonregulated operations	0.04	(0.05)	0.09
Consolidated diluted EPS	$ 0.02	$ (0.07)	$ 0.09

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$ 176,848	$ 148,778	$ 28,070
Nonregulated operations	30,082	29,971	111
Consolidated net income	$ 206,930	$ 178,749	$ 28,181
Diluted EPS from regulated operations	$ 1.93	$ 1.66	$ 0.27
Diluted EPS from nonregulated operations	0.33	0.33	
Consolidated diluted EPS	$ 2.26	$ 1.99	$ 0.27

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Three Months Ended June 30, 2009 compared with Three Months Ended June 30, 2008

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 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia	October	May
Kansas	October	May
Kentucky	November	April
Louisiana	December	March
Mississippi	November	April
Tennessee	November	April
Texas: Mid-Tex	November	April
Texas: West Texas	October	May
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.

Gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact of these timing differences is generally offset within operating income. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective which should significantly reduce the impact of this timing difference on a prospective basis. However, this timing difference will still be present for gross receipts taxes.

Higher gas costs may also 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. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

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Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 191,682	$ 199,928	$ (8,246)
Operating expenses	184,299	194,731	(10,432)
Operating income	7,383	5,197	2,186
Miscellaneous income	2,167	3,508	(1,341)
Interest charges	32,798	28,504	4,294
Loss before income taxes	(23,248)	(19,799)	(3,449)
Income tax benefit	(8,307)	(7,421)	(886)
Net loss	$ (14,941)	$ (12,378)	$ (2,563)
Consolidated natural gas distribution sales volumes MMcf	40,081	41,357	(1,276)
Consolidated natural gas distribution transportation volumes MMcf	29,597	32,126	(2,529)
Total consolidated natural gas distribution throughput MMcf	69,678	73,483	(3,805)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.43	$ 0.03
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.87	$ 11.53	$ (6.66)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended June 30, 2009 and 2008. 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 June 30		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$ (3,598)	$ (3,043)	$ (555)
Kentucky/Mid-States	2,931	5,757	(2,826)
Louisiana	5,459	5,086	373
West Texas	1,010	(563)	1,573
Mississippi	(585)	(946)	361
Colorado-Kansas	1,247	542	705
Other	919	(1,636)	2,555

Total	$ 7,383	$ 5,197	$ 2,186

The $8.2 million decrease in natural gas distribution gross profit primarily reflects a net $5.4 million decrease in margins in the Mid-Tex Division. This reduction in margins was primarily due to rate design changes implemented in November 2008 that decreased the monthly base charge and increased the volumetric charge for most of the Mid-Tex Division s customers. This change results in higher gross profit during the winter heating season and lower gross profit in the summer months. The current year period also reflects a $3.3 million increase in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. The

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decrease in gross profit also reflects a $3.5 million decrease as a result of a five percent decrease in distribution throughput, primarily associated with lower residential, commercial and industrial consumption. Finally, service revenue and late charges, which are based on the customer s outstanding balance, decreased $1.3 million due to the lower cost of natural gas in the current-year period.

Partially offsetting these decreases was an increase of approximately $1.3 million in revenue-related taxes in the current-year quarter compared to the prior-year quarter primarily due to the timing change in franchise fees in our Mid-Tex Division. This increase was combined with a $9.5 million quarter-over-quarter decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes, other than income, resulting in a $10.8 million increase in operating income when compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income, and asset impairments decreased $10.4 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $4.9 million, primarily due to lower legal and other administrative costs. These decreases were partially offset by a $2.8 million noncash charge to impair certain available-for-sale investments as the Company believed the fair value of these investments would not recover within a reasonable period of time.

Depreciation and amortization expense increased $3.2 million for the third quarter of fiscal 2009 compared with third quarter of fiscal 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Interest charges allocated to the natural gas distribution segment increased $4.3 million due to the effect of the Company s March 2009 issuance of $450 million 8.50% senior notes to repay $400 million 4.00% senior notes in April 2009.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2009 are discussed below. The amounts described below 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 final ruling.

Annual Rate Filing Mechanisms

In March 2009, the Mid-Tex Division filed its second Rate Review Mechanism (RRM) with the Settled Cities. The filing requested an increase in annual operating income of $9.7 million for the Settled Cities. The Mid-Tex Division and representatives of the Settled Cities reached an agreement to increase annual operating income by $2.0 million, which will be implemented in rates beginning in August 2009. Beginning in November 2008, rates were implemented from our first RRM filing with the Settled Cities, which resulted in an increase in annual operating income on a system-wide basis of approximately $27.3 million. The impact to the Mid-Tex Division for the Settled Cities was approximately $21.8 million.

In April 2009, the West Texas Division filed its second RRM with the West Texas Cities. The filing requested an increase in annual operating income of $11.1 million. The West Texas Division and representatives of the West Texas Cities reached an agreement to increase annual operating income $7.8 million, which will be implemented in rates beginning in August 2009. Beginning in November 2008, rates were implemented from our first RRM with the West Texas Cities, which resulted in an increase in operating income of $4.5 million, of which $3.9 million is being

collected over a 91/2 month period.

In April 2009, the City of Lubbock approved an RRM tariff similar to the RRM tariff utilized by the West Texas Cities. The West Texas Division filed its first RRM with the City of Lubbock on April 15, 2009. The filing requested an increase in annual operating income of $3.5 million. The City of Lubbock is currently reviewing the filing and a final determination is expected in October 2009.

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In June 2009, the City of Amarillo approved an RRM tariff similar to the RRM tariff utilized by the West Texas Cities. The West Texas Division filed its first RRM with the City of Amarillo on June 17, 2009. The filing requested an annual increase in operating income of $2.3 million. The City of Amarillo is currently reviewing the filing and a final determination is expected in October 2009.

In December 2008, the Louisiana Division filed its TransLa annual rate stabilization clause with the Louisiana Public Service Commission (LPSC) for the test year ended September 30, 2008. The filing resulted in an annual increase in operating income of $0.6 million and was implemented in April 2009.

In April 2009, the Louisiana Division filed its LGS annual rate stabilization clause with the LPSC. The filing was for the test year ended December 31, 2008. The filing resulted in an annual increase in operating income of $3.3 million and was implemented in July 2009.

In September 2008, we filed our Mississippi stable rate filing with the Mississippi Public Service Commission (MPSC) requesting an increase in annual operating income of $3.5 million. In January 2009, we withdrew this request after we were unable to reach a mutually agreeable settlement with the MPSC.

GRIP Filings

In May 2008, the Mid-Tex Division made a GRIP filing seeking a $10.3 million increase on a system-wide basis. However, this filing was only applicable to the City of Dallas and the Mid-Tex environs and sought a $1.8 million increase for customers in those service areas. Rates were approved for this filing in December 2008 and were implemented in January 2009. However, in April 2009, the City of Dallas challenged the legality of the implementation of the GRIP rates, which the Company is contesting in the District Courts of Dallas and Travis Counties.

In March 2009, the Mid-Tex Division made a GRIP filing seeking an $18.7 million increase on a system-wide basis. However, this filing is applicable to the City of Dallas only and seeks a $2.7 million increase for customers in the City of Dallas. The City of Dallas denied this GRIP filing in June 2009 and the Mid-Tex Division has appealed this action to the Railroad Commission of Texas (RRC).

Any rate increases granted from these GRIP filings will be in effect until such time that they are superseded by the statement of intent filed with the City of Dallas discussed below.

Rate Case Filings

In October 2008, our Kentucky/Mid-States Division filed a rate case with the Tennessee Regulatory Authority seeking an increase in annual operating income of $6.3 million. In January 2009, the Consumer Advocate and Protection Division recommended a decrease in rates of $3.7 million. In March 2009, a unanimous stipulation was filed and approved in the case. The parties agreed to an increase in annual operating income of $2.5 million with a stated return on equity of 10.3 percent. The increase in rates was implemented in April 2009.

In November 2008, the Mid-Tex Division filed a statement of intent to increase annual operating income for customers within the City of Dallas by $9.1 million. The City of Dallas suspended the filing in December 2008 and denied the increase in March 2009. The Mid-Tex Division has appealed the filing and in April 2009 we requested an increase in annual operating income of $7.5 million and concurrently filed for a statement of intent to increase annual operating income $1.3 million applicable to the Mid-Tex unincorporated areas. The City of Dallas has proposed a reduction of rates of $28.9 million to annual operating income system-wide, or approximately $5.8 million for the City of Dallas and environs customers. On August 4, 2009, the Mid-Tex Division filed a rebuttal revising the

requested increase in annual operating income to $6.6 million for the City of Dallas and $1.1 million for the Mid-Tex unincorporated areas. A hearing is scheduled with the RRC in August 2009 and a final ruling is expected in November 2009. If the statement of intent applicable to the City of Dallas is approved by the RRC, the new rates implemented could supersede the City of Dallas GRIP rates discussed above.

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In April 2009, the Kentucky/Mid-States Division filed an expedited rate case with the Virginia State Corporation Commission seeking an increase in annual operating income of $1.7 million. Interim rates were implemented subject to refund on May 1, 2009. The application is currently in discovery with a final determination expected in October 2009.

In July 2009, the Colorado/Kansas Division filed a rate case with the Colorado Public Service Commission seeking an increase in annual operating income of $3.8 million effective in August 2009. A procedural schedule has not been established; however the Commission is expected to suspend the filing.

Other Ratemaking Activity

In May 2007, our Mid-Tex Division filed for a 36-month gas contract review filing. This filing was mandated by prior RRC orders and related to the prudency of gas purchases made from November 2003 through October 2006, which total approximately $2.7 billion. The intervening parties recommended disallowances ranging from $58 million to $89 million. A hearing was held at the RRC in September 2008. In December 2008, a proposal for decision was issued by the Hearing Examiner recommending no gas cost disallowance. In February 2009, the RRC approved the Hearing Examiner s recommendation to disallow no gas costs.

In March 2009, the RRC established a procedural schedule to examine the 36-month gas contract review process. Briefs were filed in April 2009 and the Hearing Examiner issued a proposal for decision in June 2009 which recommended the elimination of the 36-month gas contract review process. The RRC has not taken any action on the proposed final order.

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 and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

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Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 19,507	$ 18,761	$ 746
Third-party transportation	24,285	22,485	1,800
Storage and park and lend services	3,137	2,387	750
Other	2,416	2,653	(237)
Gross profit	49,345	46,286	3,059
Operating expenses	21,789	24,395	(2,606)
Operating income	27,556	21,891	5,665
Miscellaneous income	615	550	65
Interest charges	8,152	6,606	1,546
Income before income taxes	20,019	15,835	4,184
Income tax expense	7,065	5,570	1,495
Net income	$ 12,954	$ 10,265	$ 2,689
Gross pipeline transportation volumes MMcf	169,641	181,112	(11,471)
Consolidated pipeline transportation volumes MMcf	141,556	152,450	(10,894)

The $3.1 million increase in gross profit was attributable primarily to a $3.5 million increase from higher demand-based fees. The improvement in gross profit also reflects a $1.1 million increase due to our GRIP filings. These increases were partially offset by a $0.7 million decrease arising from a seven percent decrease in city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses decreased $2.6 million primarily due to a decrease in pipeline maintenance costs during the current-year quarter.

Recent Ratemaking Developments

In February 2009, the Atmos Pipeline Texas Division made a GRIP filing seeking an increase in annual operating income of $6.3 million. The filing was approved by the RRC and a final order was issued in April 2009.

Natural Gas Marketing Segment

Our natural gas marketing activities are conducted through Atmos Energy Marketing, LLC (AEM). AEM aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues received for services we deliver.

Our asset optimization activities seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross

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profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time.

AEM continually manages its net physical position to attempt to increase in the future the potential economic gross profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to economically hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the execution of the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended June 30, 2009 and 2008 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical (spot) and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the

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unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 16,598	$ 11,231	$ 5,367
Asset optimization	(14,580)	(37,551)	22,971
	2,018	(26,320)	28,338
Unrealized margins	13,004	23,689	(10,685)
Gross profit	15,022	(2,631)	17,653
Operating expenses	7,555	5,205	2,350
Operating income	7,467	(7,836)	15,303
Miscellaneous income	71	377	(306)
Interest charges	4,020	2,850	1,170
Income (loss) before income taxes	3,518	(10,309)	13,827
Income tax expense (benefit)	1,419	(3,995)	5,414
Net income (loss)	$ 2,099	$ (6,314)	$ 8,413
Gross natural gas marketing sales volumes MMcf	103,146	103,403	(257)
Consolidated natural gas marketing sales volumes MMcf	84,162	82,122	2,040
Net physical position (Bcf)	20.0	17.5	2.5

The $17.7 million increase in our natural gas marketing segment s gross profit was driven primarily by a $23.0 million increase in asset optimization margins. The increase was primarily the result of a decrease in losses realized on financial settlements during the current quarter when compared to the prior-year quarter. Settlements during both years were primarily related to the deferral of storage withdrawals as AEM had elected to reset the corresponding financial instruments to future periods to increase the potential gross profit it could realize from its asset optimization activities. The reduction in realized losses was caused by greater price volatility in the prior-year period which had a greater impact on the settlement of financial instruments used to hedge our physical storage.

The increase in asset optimization margins was partially offset by a $10.7 million decrease in unrealized margins. This decrease reflects lower volatility during the current quarter compared with the prior-year quarter between current cash prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

In addition, delivered gas margins increased $5.4 million compared with the prior-year quarter largely attributable to a 48 percent increase in gross per-unit margins on similar gross sales volumes period over period as a result of greater basis opportunities in certain market areas and successful contract renewals.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments increased $2.4 million primarily due to an increase in legal and other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic gross profit, combined with the effect of the future reversal of

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unrealized gains or losses currently recognized in the income statement is referred to as the potential gross profit.[1] The following table presents AEM s economic gross profit and its potential gross profit at June 30, 2009, March 31, 2009, December 31, 2008, September 30, 2008 and June 30, 2008.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit (In millions)	Associated Net Unrealized Gain (In millions)	Potential Gross Profit[1] (In millions)
June 30, 2009	20.0	$ 42.0	$ 16.7	$ 25.3
March 31, 2009	21.9	$ 33.4	$ 2.4	$ 31.0
December 31, 2008	16.3	$ 20.7	$ 4.8	$ 15.9
September 30, 2008	8.0	$ 48.5	$ 36.4	$ 12.1
June 30, 2008	17.5	$ 48.2	$ 34.3	$ 13.9

[1] Potential gross profit represents the increase in AEM s gross profit in future periods if its optimization efforts are executed as planned. This amount does not include storage and other operating expenses and increased income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic gross profit or the potential gross profit will be fully realized in the future. We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides our investors a more comprehensive view of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone.

As of June 30, 2009, based upon AEM s planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $42.0 million. This amount will be reduced by $16.7 million of net unrealized gains recorded in the financial statements as of June 30, 2009 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit associated with these positions was $25.3 million at June 30, 2009.

During the nine months ended June 30, 2009, AEM increased its potential gross profit by $13.2 million to $25.3 million. In the first quarter, AEM withdrew gas and substantially realized the associated potential gross profit reported as of September 30, 2008. Since that time, as a result of falling current cash prices, AEM has been deferring storage withdrawals and has been a net injector of gas into storage to increase the potential gross profit it could realize in future periods from its asset optimization activities. As a result of these activities, AEM has increased its net physical position by 12.0 Bcf since September 30, 2008. However, the captured spreads on these positions have been lower than those captured as of September 30, 2008, resulting in a lower economic gross profit compared to that time. This decrease from September 2008 to June 2009 was partially offset by lower unrealized gains associated with these positions primarily due to lower current cash prices and lower volatility between cash and future prices.

The economic gross profit is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and

optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic gross profit or the potential gross profit calculated as of June 30, 2009 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted. Assuming AEM fully executes its plan in place on June 30, 2009, without encountering operational or other issues, we anticipate that approximately $15.9 million of the economic gross profit as of June 30, 2009 will be recognized in fiscal 2009 with the remaining $26.1 million expected to be recognized during the first six months of fiscal 2010.

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Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of June 30, 2009.

Results for this segment are impacted primarily by seasonal weather patterns and volatility in the natural gas markets. Additionally, this segment s results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands)		
Asset optimization	$ 1,051	$ (484)	$ 1,535
Storage and transportation services	3,470	3,464	6
Other	737	592	145
Unrealized margins	(1,244)	(398)	(846)
Gross profit	4,014	3,174	840
Operating expenses	2,823	1,803	1,020
Operating income	1,191	1,371	(180)
Miscellaneous income	2,319	2,273	46
Interest charges	408	532	(124)
Income before income taxes	3,102	3,112	(10)
Income tax expense	1,250	1,273	(23)
Net income	$ 1,852	$ 1,839	$ 13

Gross profit from our pipeline, storage and other segment increased $0.8 million primarily due to a $1.5 million increase in asset optimization margins resulting from larger basis gains earned from utilizing controlled pipeline capacity. These increases were partially offset by a $0.8 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the three months ended June 30, 2009 increased $1.0 million primarily due to increased employee costs and higher depreciation expense, which was largely attributable to additional assets placed in service during the current-year period.

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Nine Months Ended June 30, 2009 compared with Nine Months Ended June 30, 2008

Natural Gas Distribution Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands, unless otherwise noted)		
Gross profit	$ 857,146	$ 830,652	$ 26,494
Operating expenses	563,530	564,440	(910)
Operating income	293,616	266,212	27,404
Miscellaneous income	6,123	7,654	(1,531)
Interest charges	94,506	88,802	5,704
Income before income taxes	205,233	185,064	20,169
Income tax expense	68,465	71,622	(3,157)
Net income	$ 136,768	$ 113,442	$ 23,326
Consolidated natural gas distribution sales volumes MMcf	253,087	261,692	(8,605)
Consolidated natural gas distribution transportation volumes MMcf	98,994	105,605	(6,611)
Total consolidated natural gas distribution throughput MMcf	352,081	367,297	(15,216)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.44	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.18	$ 8.77	$ (1.59)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the nine months ended June 30, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands)		
Mid-Tex	$ 129,454	$ 119,661	$ 9,793

Kentucky/Mid-States	49,360	49,800	(440)
Louisiana	39,825	36,254	3,571
West Texas	23,829	13,332	10,497
Mississippi	24,621	23,397	1,224
Colorado-Kansas	23,471	22,766	705
Other	3,056	1,002	2,054
Total	$ 293,616	$ 266,212	$ 27,404

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The $26.5 million increase in natural gas distribution gross profit primarily reflects a net $35.1 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $22.4 million as a result of the implementation of its 2008 Rate Review Mechanism (RRM) filing with all incorporated cities in the division other than the City of Dallas (the Settled Cities) and rate adjustments for customers in the City of Dallas. The current year period also reflects a $12.7 million increase in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. The increase in gross profit also reflects the reversal of a $7.0 million uncollectible gas cost accrual recorded in a prior year and a $7.8 million increase attributable to a non-recurring update to our estimate for gas delivered to customers but not yet billed to reflect changes in base rates in several of our jurisdictions recorded in the fiscal first quarter. These increases in gross profit were partially offset by an $18.8 million decrease as a result of a four percent decrease in distribution throughput primarily associated with lower residential, commercial and industrial consumption and warmer weather in our Colorado service area, which does not have weather-normalized rates.

Partially offsetting these increases was a decrease of approximately $8.0 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year period compared to the prior-year period. This decrease, partially offset by a $2.2 million period-over-period decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $5.8 million decrease in operating income when compared with the prior-year period.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income, and asset impairments decreased $0.9 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $11.3 million, primarily due to lower legal, fuel and other administrative costs. These decreases were partially offset by a $4.6 million noncash charge to impair certain available-for-sale investments as the Company believed the fair value of these investments would not recover within a reasonable period of time.

Depreciation and amortization expense increased $11.9 million for the current-year period compared with nine months ended June 30, 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Results for the prior-year period also included a $1.2 million gain on the sale of irrigation assets in our West Texas Division.

Interest charges allocated to the natural gas distribution segment increased $5.7 million primarily due to the effect of the Company s March 2009 issuance of $450 million 8.50% senior notes to repay $400 million 4.00% senior notes in April 2009. In addition, higher average short-term debt balances, interest rates and commitment fees were experienced during the current-year period compared to the prior-year period.

Results for the current-year period include a $10.5 million tax benefit associated with updating the rates used to determine our deferred taxes.

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Regulated Transmission and Storage Segment

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 70,920	$ 69,409	$ 1,511
Third-party transportation	73,497	58,946	14,551
Storage and park and lend services	8,151	6,288	1,863
Other	10,693	8,129	2,564
Gross profit	163,261	142,772	20,489
Operating expenses	82,006	68,565	13,441
Operating income	81,255	74,207	7,048
Miscellaneous income	1,713	933	780
Interest charges	23,580	20,453	3,127
Income before income taxes	59,388	54,687	4,701
Income tax expense	19,308	19,351	(43)
Net income	$ 40,080	$ 35,336	$ 4,744
Gross pipeline transportation volumes MMcf	555,169	593,452	(38,283)
Consolidated pipeline transportation volumes MMcf	400,699	429,758	(29,059)

The $20.5 million increase in gross profit was attributable primarily to an $11.0 million increase from higher demand-based fees and a $7.5 million increase resulting from higher transportation fees on through-system deliveries due to market conditions. The improvement in gross profit also reflects a $3.8 million increase due to our GRIP filings and a $2.9 million gain on the sale of excess gas during the current-year period. These increases were partially offset by a $4.2 million decrease associated with a seven percent decrease in city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $13.4 million primarily due to increased employee and pipeline maintenance costs.

Results for the current-year period also include a $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

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Natural Gas Marketing Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 58,316	$ 55,599	$ 2,717
Asset optimization	20,286	(10,339)	30,625
	78,602	45,260	33,342
Unrealized margins	(10,013)	14,404	(24,417)
Gross profit	68,589	59,664	8,925
Operating expenses	30,230	22,775	7,455
Operating income	38,359	36,889	1,470
Miscellaneous income	490	1,775	(1,285)
Interest charges	11,383	6,166	5,217
Income before income taxes	27,466	32,498	(5,032)
Income tax expense	11,444	12,933	(1,489)
Net income	$ 16,022	$ 19,565	$ (3,543)
Gross natural gas marketing sales volumes MMcf	336,870	348,789	(11,919)
Consolidated natural gas marketing sales volumes MMcf	282,443	298,351	(15,908)
Net physical position (Bcf)	20.0	17.5	2.5

The $8.9 million increase in our natural gas marketing segment s gross profit was driven primarily by a $30.6 million increase in asset optimization margins. During the first quarter of fiscal 2009, AEM withdrew physical storage inventory and realized the spreads it had captured during fiscal 2008 as a result of deferring storage withdrawals and increasing the spreads associated with those physical positions. These gains were partially offset by margin losses incurred in the second and third fiscal quarters as a result of deferring storage withdrawals and injecting gas into storage. In the prior-year period, AEM deferred storage withdrawals from the first quarter into the second quarter, and recognized the storage withdrawal gains during the second quarter of fiscal 2008.

The increase in asset optimization margins was partially offset by a $24.4 million decrease in unrealized margins. This decrease reflects lower volatility during the current year compared with the prior-year period between current cash

prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

Additionally, realized delivered gas margins increased by $2.7 million. The increase was largely attributable to a nine percent increase in gross per-unit margins as a result of improved basis spreads in certain market areas where we were able to better optimize transportation assets and successful contract renewals, partially offset by a three percent decrease in gross sales volumes primarily associated with lower industrial demand due to the current economic climate.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments increased $7.5 million primarily due to an increase in legal and other administrative costs partially offset by the absence in the current year of $2.4 million related to tax matters incurred in the prior-year period.

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Pipeline, Storage and Other Segment

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	**2008**	**Change**
	(In thousands)		
Asset optimization	$ 21,675	$ 5,890	$ 15,785
Storage and transportation services	10,097	10,487	(390)
Other	2,076	2,432	(356)
Unrealized margins	(6,673)	47	(6,720)
Gross profit	27,175	18,856	8,319
Operating expenses	7,239	6,061	1,178
Operating income	19,936	12,795	7,141
Miscellaneous income	6,540	6,243	297
Interest charges	1,821	1,755	66
Income before income taxes	24,655	17,283	7,372
Income tax expense	10,595	6,877	3,718
Net income	$ 14,060	$ 10,406	$ 3,654

Gross profit from our pipeline, storage and other segment increased $8.3 million primarily due to a $15.8 million increase in asset optimization margins as a result of larger realized gains from the settlement of financial positions associated with storage and trading activities, basis gains earned from utilizing controlled pipeline capacity and higher margins earned under asset management plans during the current-year period compared with the prior-year period. These increases were partially offset by a $6.7 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the nine months ended June 30, 2009 increased $1.2 million primarily due to increased employee costs and higher depreciation expense which was largely attributable to additional assets placed in service during the current-year period.

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.

The primary means we use to fund our working capital needs and growth is to utilize internally generated funds and to access the commercial paper markets. Recent adverse developments in global financial and credit markets have made it more difficult and more expensive for the Company to access the short-term capital markets, including the commercial paper market, to satisfy our liquidity requirements. Consequently, during the first quarter, we experienced higher than normal borrowings under our five-year credit facility used to backstop our commercial paper program in lieu of commercial paper borrowings to fund our working capital needs. However, subsequent to the end of the first quarter, credit market conditions improved, both as to availability and interest rates, and we have been able to access the commercial paper markets on more reasonably economical terms. At June 30, 2009, there were no borrowings or commercial paper outstanding under this facility and $566.7 million was available.

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On March 26, 2009, we closed our offering of $450 million of 8.50% senior notes due 2019. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds were used for general corporate purposes.

During the nine months ended June 30, 2009, we enhanced our liquidity sources in various ways. In October 2008, we replaced our former $300 million 364-day committed credit facility with a new facility that will allow borrowings up to $212.5 million and expires in October 2009. We are currently evaluating alternatives to replace this facility and believe we will successfully replace this facility on reasonably economical terms.

In December 2008, we converted AEM s former $580 million uncommitted credit facility to a $375 million committed credit facility that will expire in December 2009. Effective April 1, 2009, we exercised the accordion feature of this facility to increase the credit available under the facility to $450 million. In addition, we replaced our $18 million unsecured committed credit facility that expired in March 2009 with a $25 million unsecured facility effective April 1, 2009. As a result of executing these new agreements, we have a total of approximately $1.3 billion available to us under four committed credit facilities. As of June 30, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $905 million.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2009.

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 activities

Period-over-period changes in our operating cash flows primarily are attributable to changes in net income and working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the nine months ended June 30, 2009, we generated operating cash flow of $824.6 million from operating activities compared with $417.4 million for the nine months ended June 30, 2008. Period over period, the $407.2 million increase was attributable primarily to the favorable impact on our working capital due to the decline in natural gas prices in the current year compared to the prior-year period which increased operating cash flow by $251.1 million. The increase in operating cash flow was also positively impacted by $99.9 million due to lower cash margin requirements related to our natural gas marketing financial instruments and by $49.0 million due to the favorable timing in the recovery of gas costs during the current year. Partially offsetting these increases in operating cash flows was the $21.0 million contribution to our pension plans in the current year.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us 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,

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expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return on our investment. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline Texas Division have rate designs 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.

Capital expenditures for fiscal 2009 are expected to range from $500 million to $515 million. For the nine months ended June 30, 2009, capital expenditures were $342.3 million compared with $312.9 million for the nine months ended June 30, 2008. The increase in capital spending primarily reflects spending for a nonregulated growth project and the construction of a pipeline extension in our regulated operations.

Cash flows from financing activities

For the nine months ended June 30, 2009, our financing activities used $397.2 million compared with $114.4 million in the prior-year period. Our significant financing activities for the nine months ended June 30, 2009 and 2008 are summarized as follows:

On March 26, 2009, we issued $450 million of 8.50% senior notes due 2019. The effective interest rate of this offering, inclusive of all debt issue costs, was 8.74 percent. After giving effect to the settlement of our $450 million Treasury lock agreement on March 23, 2009, the effective rate on these senior notes was reduced to 8.69 percent. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes on April 30, 2009.

During the nine months ended June 30, 2009, we decreased our borrowings by a net $366.4 million under our short-term credit facilities compared with $35.7 million in the prior-year period. The reduction in the net borrowings reflects the combination of increased cash flows and lower natural gas prices during the current year.

We repaid $407.3 million of long-term debt during the nine months ended June 30, 2009 compared with $9.9 million during the nine months ended June 30, 2008. The increase in payments in the current year reflects the redemption of our $400 million unsecured 4.00% senior notes discussed above.

During the nine months ended June 30, 2009, we paid $90.9 million in cash dividends compared with $87.8 million for the nine months ended June 30, 2008. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.975 per share during the nine months ended June 30, 2008 to $0.99 per share during the nine months ended June 30, 2009 combined with new share issuances under our various equity plans.

During the nine months ended June 30, 2009, we issued 0.9 million shares of common stock under our various equity plans, which generated net proceeds of $19.9 million. In addition, we issued 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the nine months ended June 30, 2009 and 2008.

	Nine Months Ended June 30	
	2009	**2008**

Shares issued:		
Direct Stock Purchase Plan	319,732	294,071
Retirement Savings Plan and Trust	484,111	410,350
1998 Long-Term Incentive Plan	613,314	538,100
Outside Directors Stock-for-Fee Plan	2,294	2,399
Total shares issued	1,419,451	1,244,920

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Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding. As of June 30, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $905 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006. Immediately following the filing of the registration statement, we issued $450 million of 8.50% senior notes due 2019 under the registration statement. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes on April 30, 2009.

As of June 30, 2009, we had $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

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). In December 2008, S&P upgraded our senior long-term debt credit rating from BBB to BBB+ and changed our rating outlook from positive to stable. S&P cited improved financial performance and rate case decisions that have increased cash flow as the key drivers for the upgrade. In January 2009, Moody s changed our rating outlook from stable to positive. In May 2009, Moody s upgraded the credit rating on our senior long-term debt from Baa3 to Baa2 and on our commercial paper from P-3 to P-2 and changed our rating outlook from positive to stable. Moody s stated that the key drivers for the upgrade were the completion of a major debt refinancing and the Company improving its alternate liquidity resources while maintaining solid financial performance. Fitch still maintains its stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody s	Fitch

Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of the recent adverse global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in

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

Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2009. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2009, September 30, 2008 and June 30, 2008:

	June 30, 2009		September 30, 2008		June 30, 2008	
	(In thousands, except percentages)					
Short-term debt	$	%	$ 350,542	7.7%	$ 113,257	2.6%
Long-term debt	2,169,526	49.7%	2,120,577	46.9%	2,120,788	48.9%
Shareholders equity	2,191,520	50.3%	2,052,492	45.4%	2,105,407	48.5%
Total	$ 4,361,046	100.0%	$ 4,523,611	100.0%	$ 4,339,452	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 49.7 percent at June 30, 2009, 54.6 percent at September 30, 2008 and 51.5 percent at June 30, 2008. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2009.

In February 2008, Atmos Pipeline and Storage, LLC announced plans to construct and operate a salt-cavern gas storage project in Franklin Parish, Louisiana. The project, located near several large interstate pipelines, includes the development of three 5 billion cubic feet (Bcf) caverns for a total of 15 Bcf of working gas storage, with six-turn injection and withdrawal capacity. Testing of the salt core samples was completed in March 2009 which showed favorable conditions for development. In June 2009, we received our 7C certification from the Federal Energy

Regulatory Commission (FERC) to construct and operate the project and expect approval of this request in June 2009. Finally, we have engaged the services of an investment bank to assist us in determining the optimal ownership and/or development alternatives for this project, which is still in process.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical

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storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our natural gas marketing and pipeline, storage and other segments, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

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 nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$ (21,863)	$ 9,505	$ (63,677)	$ (21,053)
Contracts realized/settled	(844)	339	(101,840)	(26,971)
Fair value of new contracts	(885)	5,675	(4,891)	5,395
Other changes in value	1,564	21,847	148,380	79,995
Fair value of contracts at end of period	$ (22,028)	$ 37,366	$ (22,028)	$ 37,366

The fair value of our natural gas distribution segment s financial instruments at June 30, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2009 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	$ (21,712)	$ (316)	$	$	$ (22,028)
Prices based on models and other valuation methods					
Total Fair Value	$ (21,712)	$ (316)	$	$	$ (22,028)

The following table shows the components of the change in fair value of our natural gas marketing segment s financial instruments for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended	Nine Months Ended

	June 30		June 30	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$ (32,646)	$ (22,975)	$ 16,542	$ 26,808
Contracts realized/settled	42,535	30,185	29,260	(11,071)
Fair value of new contracts				
Other changes in value	8,555	(50,182)	(27,358)	(58,709)
Fair value of contracts at end of period	18,444	(42,972)	18,444	(42,972)
Netting of cash collateral	20,614	62,152	20,614	62,152
Cash collateral and fair value of contracts at period end	$ 39,058	$ 19,180	$ 39,058	$ 19,180

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The fair value of our natural gas marketing segment s financial instruments at June 30, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2009 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	$ 8,544	$ 9,900	$	$	$ 18,444
Prices based on models and other valuation methods					
Total Fair Value	$ 8,544	$ 9,900	$	$	$ 18,444

Pension and Postretirement Benefits Obligations

Effective October 1, 2008, the Company adopted the requirement under SFAS 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* that the measurement date used to determine our projected benefit and postretirement obligations and net periodic pension and postretirement costs must correspond to a fiscal year end. In accordance with the transition rules, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million.

Further, our fiscal 2009 costs were determined using a September 30, 2008 measurement date. As of September 30, 2008, interest and corporate bond rates utilized to determine our discount rates were significantly higher than the interest and corporate bond rates as of June 30, 2007, the measurement date for our fiscal 2008 net periodic cost. Accordingly, we increased our discount rate used to determine our fiscal 2009 pension and benefit costs to 7.57 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that assets are smoothed for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Therefore, our fiscal 2009 pension and postretirement medical costs were materially the same as in fiscal 2008.

For the nine months ended June 30, 2009 and 2008, our total net periodic pension and other benefits cost was $36.2 million and $35.9 million. 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.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we contributed $21 million to our pension plans in June 2009. The need for this funding reflected the decline in the fair value of the plans assets resulting from the unfavorable market conditions experienced during the latter half of calendar year 2008. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate

contributing a total of approximately $11 million to these plans during fiscal 2009.

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

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OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three and nine-month periods ended June 30, 2009 and 2008.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	**2008**	**2009**	**2008**
METERS IN SERVICE, end of period				
Residential	2,924,160	2,922,415	2,924,160	2,922,415
Commercial	274,739	271,542	274,739	271,542
Industrial	2,195	2,265	2,195	2,265
Public authority and other	9,231	9,234	9,231	9,234
Total meters	3,210,325	3,205,456	3,210,325	3,205,456
INVENTORY STORAGE BALANCE Bcf	37.9	41.7	37.9	41.7
SALES VOLUMES MMcf[1]				
Gas sales volumes				
Residential	19,043	18,584	147,718	151,549
Commercial	14,398	15,199	79,416	82,325
Industrial	3,921	4,687	15,079	17,899
Public authority and other	2,719	2,887	10,874	9,919
Total gas sales volumes	40,081	41,357	253,087	261,692
Transportation volumes	30,637	33,211	102,091	109,002
Total throughput	70,718	74,568	355,178	370,694
OPERATING REVENUES (000 $)[1]				
Gas sales revenues				
Residential	$ 224,629	$ 352,893	$ 1,657,185	$ 1,878,855
Commercial	106,739	213,594	744,248	903,771
Industrial	21,028	53,843	117,442	167,154
Public authority and other	13,712	33,135	82,097	100,983
Total gas sales revenues	366,108	653,465	2,600,972	3,050,763
Transportation revenues	13,756	14,163	46,411	46,954
Other gas revenues	7,121	9,011	25,990	28,955
Total operating revenues	$ 386,985	$ 676,639	$ 2,673,373	$ 3,126,672
Average transportation revenue per Mcf	$ 0.45	$ 0.43	$ 0.45	$ 0.43
Average cost of gas per Mcf sold	$ 4.87	$ 11.53	$ 7.18	$ 8.77

See footnote following these tables.

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Regulated Transmission and Storage, Natural Gas Marketing and Pipeline, Storage and Other Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
CUSTOMERS, end of period				
Industrial	706	702	706	702
Municipal	63	56	63	56
Other	505	503	505	503
Total	1,274	1,261	1,274	1,261
INVENTORY STORAGE BALANCE Bcf				
Natural gas marketing	23.3	18.8	23.3	18.8
Pipeline, storage and other	2.5	1.2	2.5	1.2
Total	25.8	20.0	25.8	20.0
REGULATED TRANSMISSION AND STORAGE VOLUMES MMcf[1]	169,641	181,112	555,169	593,452
NATURAL GAS MARKETING SALES VOLUMES MMcf[1]	103,146	103,403	336,870	348,789
OPERATING REVENUES (000 s)[1]				
Regulated transmission and storage	$ 49,345	$ 46,286	$ 163,261	$ 142,772
Natural gas marketing	453,504	1,189,722	1,949,657	3,159,092
Pipeline, storage and other	8,226	3,880	36,946	20,629
Total operating revenues	$ 511,075	$ 1,239,888	$ 2,149,864	$ 3,322,493

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. During the nine months ended June 30, 2009, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management s Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company s disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company s principal executive officer and principal financial officer have concluded that the Company s disclosure controls and procedures were effective as of June 30, 2009 to provide reasonable assurance that information

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required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC s rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2009 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 nine months ended June 30, 2009, except as noted in Note 8 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 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. 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.

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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/ Fred E. Meisenheimer
Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 5, 2009

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EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number
10.1	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.2	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
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*	

* 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.