Atmos Energy Corp.; Kentucky-Mid States Division
Kentucky Jurisdiction Case No. 2009-00354
Forecasted Test Period Filing Requirements

FR 10(9)(p)

Description of Filing Requirement:

SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters;

Response:

See attached.

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

Form 10-Q

(Mark One)

☑ **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

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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 ☐ No ☐

* 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 ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

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

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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2009	September 30, 2008
	(Unaudited)	
	(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

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

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

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

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.

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.

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.

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.

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 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.

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 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 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.

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 Marketing	Pipeline, Storage and 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)

	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.

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)

	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.

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'*

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.

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.

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

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-

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.

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.

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

	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.

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:

	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, 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 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.

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

	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

	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

	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

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

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

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

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", "seek", "strategy" or similar 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.

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 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

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

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.

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 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 9½ 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.

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.

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.

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 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 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 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	Economic Gross Profit	Associated Net Unrealized Gain	Potential Gross Profit[1]
	(Bcf)	(In millions)	(In millions)	(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.

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.

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

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.

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.

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.

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.

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, 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

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 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 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 June 30		Nine Months Ended 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

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.

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's)[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.

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 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.

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

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.

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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2009

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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 ☐ No ☐

* 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 ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of April 22, 2009.

Class	Shares Outstanding
No Par Value	92,008,920

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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2009	September 30, 2008
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,873,028	$5,730,156
Less accumulated depreciation and amortization	1,609,836	1,593,297
Net property, plant and equipment	4,263,192	4,136,859
Current assets		
Cash and cash equivalents	482,085	46,717
Accounts receivable, net	531,749	477,151
Gas stored underground	327,288	576,617
Other current assets	137,433	184,619
Total current assets	1,478,555	1,285,104
Goodwill and intangible assets	738,772	739,086
Deferred charges and other assets	205,242	225,650
	$6,685,761	$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: March 31, 2009 — 91,947,614 shares; September 30, 2008 — 90,814,683 shares	$ 460	$ 454
Additional paid-in capital	1,768,307	1,744,384
Retained earnings	480,355	343,601
Accumulated other comprehensive loss	(70,628)	(35,947)
Shareholders' equity	2,178,494	2,052,492
Long-term debt	2,169,141	2,119,792
Total capitalization	4,347,635	4,172,284
Current liabilities		
Accounts payable and accrued liabilities	472,078	395,388
Other current liabilities	413,764	460,372
Short-term debt	—	350,542
Current maturities of long-term debt	400,225	785
Total current liabilities	1,286,067	1,207,087
Deferred income taxes	466,868	441,302
Regulatory cost of removal obligation	313,486	298,645
Deferred credits and other liabilities	271,705	267,381
	$6,685,761	$6,386,699

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,230,420	$1,521,856
Regulated transmission and storage segment	59,234	51,440
Natural gas marketing segment	708,658	1,128,653
Pipeline, storage and other segment	12,272	10,022
Intersegment eliminations	(189,178)	(227,986)
	1,821,406	2,483,985
Purchased gas cost		
Natural gas distribution segment	863,340	1,164,332
Regulated transmission and storage segment	—	—
Natural gas marketing segment	685,114	1,112,321
Pipeline, storage and other segment	1,656	338
Intersegment eliminations	(188,755)	(227,400)
	1,361,355	2,049,591
Gross profit	460,051	434,394
Operating expenses		
Operation and maintenance	121,740	120,053
Depreciation and amortization	53,450	48,790
Taxes, other than income	58,314	54,408
Total operating expenses	233,504	223,251
Operating income	226,547	211,143
Miscellaneous income (expense)	(1,565)	1,467
Interest charges	35,533	33,516
Income before income taxes	189,449	179,094
Income tax expense	60,446	67,560
Net income	$ 129,003	$ 111,534
Basic net income per share	$ 1.42	$ 1.25
Diluted net income per share	$ 1.41	$ 1.24
Cash dividends per share	$ 0.330	$ 0.325
Weighted average shares outstanding:		
Basic	90,895	89,314
Diluted	91,567	89,990

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,286,388	$2,450,033
Regulated transmission and storage segment	113,916	96,486
Natural gas marketing segment	1,496,153	1,969,370
Pipeline, storage and other segment	28,720	16,749
Intersegment eliminations	(387,439)	(391,143)
	3,537,738	4,141,495
Purchased gas cost		
Natural gas distribution segment	1,620,924	1,819,309
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,442,586	1,907,075
Pipeline, storage and other segment	5,559	1,067
Intersegment eliminations	(386,594)	(389,988)
	2,682,475	3,337,463
Gross profit	855,263	804,032
Operating expenses		
Operation and maintenance	256,495	241,242
Depreciation and amortization	106,576	97,303
Taxes, other than income	102,451	95,835
Total operating expenses	465,522	434,380
Operating income	389,741	369,652
Miscellaneous income (expense)	(1,866)	1,374
Interest charges	74,524	70,333
Income before income taxes	313,351	300,693
Income tax expense	108,385	115,356
Net income	$ 204,966	$ 185,337
Basic net income per share	$ 2.26	$ 2.08
Diluted net income per share	$ 2.24	$ 2.06
Cash dividends per share	$ 0.66	$ 0.65
Weighted average shares outstanding:		
Basic	90,637	89,133
Diluted	91,311	89,817

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 204,966	$ 185,337
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	106,576	97,303
Charged to other accounts	21	67
Deferred income taxes	97,892	72,277
Other	13,634	6,853
Net assets/liabilities from risk management activities	5,810	(22,667)
Net change in operating assets and liabilities	185,723	140,022
Net cash provided by operating activities	614,622	479,192
Cash Flows From Investing Activities		
Capital expenditures	(221,330)	(198,722)
Other, net	(3,925)	(3,132)
Net cash used in investing activities	(225,255)	(201,854)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(353,468)	(150,582)
Net proceeds from debt offering	446,188	—
Settlement of Treasury lock agreement	1,938	—
Repayment of long-term debt	(625)	(2,253)
Cash dividends paid	(60,446)	(58,431)
Issuance of common stock	12,414	12,839
Net cash provided by (used in) financing activities	46,001	(198,427)
Net increase in cash and cash equivalents	435,368	78,911
Cash and cash equivalents at beginning of period	46,717	60,725
Cash and cash equivalents at end of period	$ 482,085	$ 139,636

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 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 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.

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 March 31, 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 six-month period ended March 31, 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 were no changes to those policies. However, during the six months ended March 31, 2009, we recognized a non-recurring $8.3 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*, SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* and FASB Staff Position (FSP) FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. Except for the adoption of these accounting pronouncements, which are further discussed below, there were no significant changes to our accounting policies during the six months ended March 31, 2009.

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 its projected benefit obligation, fair value of plan assets and its 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.

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 March 31, 2009 and September 30, 2008 included the following:

	March 31, 2009	September 30, 2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 89,244	$100,563
Merger and integration costs, net	7,374	7,586
Deferred gas costs	58,660	55,103
Environmental costs	741	980
Rate case costs	9,144	12,885
Deferred franchise fees	597	651
Deferred income taxes, net	343	343
Other	7,846	8,120
	$173,949	$186,231
Regulatory liabilities:		
Deferred gas costs	$ 61,177	$ 76,979
Regulatory cost of removal obligation	329,120	317,273
Other	5,499	5,639
	$395,796	$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.

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and six-month periods ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Net income	$129,003	$111,534	$204,966	$185,337
Unrealized holding losses on investments, net of tax benefit of $429 and $1,385 for the three months ended March 31, 2009 and 2008 and of $3,759 and $671 for the six months ended March 31, 2009 and 2008	(862)	(2,262)	(6,295)	(1,097)
Other than temporary impairment of investments, net of tax expense of $790 for the six months ended March 31, 2009	—	—	1,288	—
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $1,353 and $482 for the three months ended March 31, 2009 and 2008 and $1,835 and $964 for the six months ended March 31, 2009 and 2008	1,854	787	2,641	1,574
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(7,524) and $2,260 for the three months ended March 31, 2009 and 2008 and $(21,341) and $7,197 for the six months ended March 31, 2009 and 2008	(9,771)	3,690	(32,315)	11,743
Comprehensive income	$120,224	$113,749	$170,285	$197,557

Accumulated other comprehensive loss, net of tax, as of March 31, 2009 and September 30, 2008 consisted of the following unrealized gains (losses):

	March 31, 2009	September 30, 2008
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains (losses) on investments	$ (4,097)	$ 910
Treasury lock agreements	(8,463)	(11,104)
Cash flow hedges	(58,068)	(25,753)
	$(70,628)	$(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 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 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 anticipated hedging approximately 29 percent, or 25.5 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 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 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. 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.

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 46 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.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges 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. Our risk management 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. We 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 March 31, 2009, AEH had net open positions (including existing storage) of less than 0.1 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 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 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 as a component of interest expense 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 March 31, 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 March 31, 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	—	(19,052)	(1,410)
	Cash Flow	—	38,822	(1,905)
	Not designated	7,727	109,450	(688)
		7,727	129,220	(4,003)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 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 $79.1 million and $56.6 million of cash held on deposit in margin accounts as of March 31, 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 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)		
March 31, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 73,163	$ 73,163
Noncurrent commodity contracts	Deferred charges and other assets	—	8,018	8,018
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(116,698)	(116,698)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,712)	(1,712)
Total		—	(37,229)	(37,229)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	676	40,262	40,938
Noncurrent commodity contracts	Deferred charges and other assets	—	5,108	5,108
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,535)	(39,098)	(61,633)
Noncurrent commodity contracts	Deferred credits and other liabilities	(4)	(1,689)	(1,693)
Total		(21,863)	4,583	(17,280)
Total Financial Instruments		$(21,863)	$ (32,646)	$ (54,509)

(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.

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 six months ended March 31, 2009 and 2008.

Unrealized margins recorded in our natural gas marketing and pipeline, storage and other segments are comprised of various components, including, but not limited to, unrealized gains and losses arising from hedge ineffectiveness. Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative instrument and the hedged item and could materially affect our results of operations for the reported period. For the three months ended March 31, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $4.2 million and $6.5 million. For the six months ended March 31, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.6 million and $45.2 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below. Although these unrealized gains and losses are currently recorded in our income statement, they are not necessarily indicative of the economic gross profit we anticipate realizing when the underlying physical and financial transactions are settled.

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 six months ended March 31, 2009 and 2008 is presented below.

	Three Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 19,870	$2,105	$ 21,975
Fair value adjustment for natural gas inventory designated as the hedged item	(18,562)	(437)	(18,999)
Total impact on revenue	$ 1,308	$1,668	$ 2,976
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 2,327	$ —	$ 2,327
Timing ineffectiveness	(1,019)	1,668	649
	$ 1,308	$1,668	$ 2,976

	Three Months Ended March 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$(33,448)	$ (735)	$(34,183)
Fair value adjustment for natural gas inventory designated as the hedged item	39,922	1,352	41,274
Total impact on revenue	$ 6,474	$ 617	$ 7,091
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (739)	$ —	$ (739)
Timing ineffectiveness	7,213	617	7,830
	$ 6,474	$ 617	$ 7,091

	Six Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 45,553	$ 6,044	$ 51,597
Fair value adjustment for natural gas inventory designated as the hedged item	(30,422)	(1,990)	(32,412)
Total impact on revenue	$ 15,131	$ 4,054	$ 19,185
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,279	$ —	$ 4,279
Timing ineffectiveness	10,852	4,054	14,906
	$ 15,131	$ 4,054	$ 19,185

	Six Months Ended March 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$(16,221)	$1,387	$(14,834)
Fair value adjustment for natural gas inventory designated as the hedged item	57,523	2,410	59,933
Total impact on revenue	$ 41,302	$3,797	$ 45,099
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 1,217	$ —	$ 1,217
Timing ineffectiveness	40,085	3,797	43,882
	$ 41,302	$3,797	$ 45,099

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.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 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 March 31, 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	$ —	$(48,585)	$16,170	$(32,415)
Gain arising from ineffective portion of commodity contracts	—	1,180	—	1,180
Total impact on revenue	—	(47,405)	16,170	(31,235)
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)	$(47,405)	$16,170	$(32,504)

	Three Months Ended March 31, 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	$ —	$(8,040)	$13,492	$ 5,452
Loss arising from ineffective portion of commodity contracts	—	(634)	—	(634)
Total impact on revenue	—	(8,674)	13,492	4,818
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)	$(8,674)	$13,492	$ 3,549

	Six Months Ended March 31, 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	$ —	$(76,829)	$24,139	$(52,690)
Gain arising from ineffective portion of commodity contracts	—	5,372	—	5,372
Total impact on revenue	—	(71,457)	24,139	(47,318)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,538)	—	—	(2,538)
Total Impact from Cash Flow Hedges	$(2,538)	$(71,457)	$24,139	$(49,856)

	Six Months Ended March 31, 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	$ —	$(17,294)	$13,916	$(3,378)
Gain arising from ineffective portion of commodity contracts	—	126	—	126
Total impact on revenue	—	(17,168)	13,916	(3,252)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,538)	—	—	(2,538)
Total Impact from Cash Flow Hedges	$(2,538)	$(17,168)	$13,916	$(5,790)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 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 March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ 1,221	$ —	$ 1,221	$ —
Forward commodity contracts	(29,544)	7,070	(64,659)	9,649
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	633	787	1,420	1,574
Forward commodity contracts	19,773	(3,380)	32,344	2,094
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ (7,917)	$ 4,477	$(29,674)	$13,317

[(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 March 31, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(2,426)	$(54,233)	$(56,659)
Thereafter	(6,037)	(3,835)	(9,872)
Total[(1)]	$(8,463)	$(58,068)	$(66,531)

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

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three and six months ended March 31, 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 March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Natural gas marketing commodity contracts	$10,593	$(14,120)	$6,761	$(13,794)
Pipeline, storage and other commodity contracts	183	(245)	100	(889)
Total impact on revenue	$10,776	$(14,365)	$6,861	$(14,683)

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 postretirement 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' 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 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.

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 March 31, 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]	March 31, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 676	$ —	$ —	$ 676
Natural gas marketing segment	45,770	80,564	—	(75,558)	50,776
Total financial instruments	45,770	81,240	—	(75,558)	51,452
Hedged portion of gas stored underground					
Natural gas marketing segment	62,912	—	—	—	62,912
Pipeline, storage and other segment[2]	3,656	—	—	—	3,656
Total gas stored underground	66,568	—	—	—	66,568
Available-for-sale securities	26,605	—	—	—	26,605
Total assets	$138,943	$81,240	$ —	$ (75,558)	$144,625
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$22,539	$ —	$ —	$ 22,539
Natural gas marketing segment	117,413	41,567	—	(154,656)	4,324
Total liabilities	$117,413	$64,106	$ —	$(154,656)	$ 26,863

(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 March 31, 2009, we had $79.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $71.6 million was used to offset financial instruments in a liability position. The remaining $7.5 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.

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 March 31, 2009:

	March 31, 2009 (In thousands)
Carrying Amount	$2,572,987
Fair Value	$2,166,454

The fair value as of March 31, 2009 was calculated utilizing discount rates ranging from 6.6 percent to 9.6 percent, remaining average maturities ranging from one to 26 years, and a credit adjustment of 6.0 percent.

5. Debt

Long-term debt

Long-term debt at March 31, 2009 and September 30, 2008 consisted of the following:

	March 31, 2009	September 30, 2008
	(In thousands)	
Unsecured 4.00% Senior Notes, due April 2009	$ 400,000	$ 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 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	684	1,309
Total long-term debt	2,572,987	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(3,621)	(3,035)
Current maturities	(400,225)	(785)
	$2,169,141	$2,119,792

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, which, on March 30, 2009, were called for redemption 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 will be 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 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 $1.2 billion of working capital funding. At March 31, 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 March 31, 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 March 31, 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. At March 31, 2009, there were no borrowings outstanding under this facility. 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.

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 March 31, 2009, our total-debt-to-

total-capitalization ratio, as defined, was 56 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 had 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 were no borrowings outstanding under this facility at March 31, 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.

The amended facility also provides the ability for AEM to increase the borrowing base up to a maximum of $450 million through an accordion feature, subject to the approval of the participating banks; 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. Effective April 1, 2009, the borrowing base was increased to $450 million as a result of the exercise of the accordion feature in the facility.

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 March 31, 2009, there were no borrowings outstanding under this credit facility. However, at March 31, 2009, AEM letters of credit totaling $48.4 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 $201.0 million at March 31, 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 March 31, 2009, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.83 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 March 31, 2009, AEM's net working capital was $251.5 million and its tangible net worth was $271.3 million.

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. A total of $60.0 million was outstanding under this facility at March 31, 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 March 31, 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 March 31, 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 March 31, 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.

6. Earnings Per Share

Basic and diluted earnings per share for the three and six months ended March 31, 2009 and 2008 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Net income	$129,003	$111,534	$204,966	$185,337
Denominator for basic income per share — weighted average common shares	90,895	89,314	90,637	89,133
Effect of dilutive securities:				
Restricted and other shares	639	583	639	585
Stock options	33	93	35	99
Denominator for diluted income per share — weighted average common shares	91,567	89,990	91,311	89,817
Income per share — basic	$ 1.42	$ 1.25	$ 2.26	$ 2.08
Income per share — diluted	$ 1.41	$ 1.24	$ 2.24	$ 2.06

There were approximately 260,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2009. There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 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 six months ended March 31, 2009 and 2008 are presented in the following table. All 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 March 31			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,703	$ 3,878	$2,946	$3,341
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	378
Amortization of prior service cost	(183)	(171)	—	—
Amortization of actuarial loss	955	1,926	—	—
Net periodic pension cost	$ 5,791	$ 6,058	$6,271	$5,916

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 7,406	$ 7,756	$ 5,892	$ 6,682
Interest cost	15,108	13,472	7,040	5,824
Expected return on assets	(12,476)	(12,621)	(1,146)	(1,430)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(366)	(342)	—	—
Amortization of actuarial loss	1,910	3,852	—	—
Net periodic pension cost	$ 11,582	$ 12,117	$12,542	$11,832

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 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. Based upon this valuation, we expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009.

We contributed $5.2 million to our other post-retirement benefit plans during the six months ended March 31, 2009. We expect to contribute a total of approximately $10 million to these plans during fiscal 2009.

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, 2008, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 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 March 31, 2009, AEM was committed to purchase 97.6 Bcf within one year, 32.5 Bcf within one to three years and 1.0 Bcf after three years under indexed contracts. AEM is committed to purchase 1.3 Bcf within one year under fixed price contracts with prices ranging from $2.59 to $7.68 per Mcf. Purchases under these contracts totaled $431.5 million and $860.3 million for the three months ended March 31, 2009 and 2008 and $959.0 million and $1,432.3 million for the six months ended March 31, 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 its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of March 31, 2009 are as follows (in thousands):

2009	$ 40,033
2010	53,425
2011	5,245
2012	6,769
2013	7,453
Thereafter	2,571
	$115,496

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. During the second quarter, we 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 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 March 31, 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 Mid-Tex, West Texas, Louisiana and Atmos Pipeline — Texas divisions. 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 six months ended March 31, 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.

Income statements for the three and six month periods ended March 31, 2009 and 2008 by segment are presented in the following tables:

	Three Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,230,196	$32,097	$549,136	$ 9,977	$ —	$1,821,406
Intersegment revenues	224	27,137	159,522	2,295	(189,178)	—
	1,230,420	59,234	708,658	12,272	(189,178)	1,821,406
Purchased gas cost	863,340	—	685,114	1,656	(188,755)	1,361,355
Gross profit	367,080	59,234	23,544	10,616	(423)	460,051
Operating expenses						
Operation and maintenance	90,710	17,327	12,323	1,889	(509)	121,740
Depreciation and amortization	47,541	5,006	396	507	—	53,450
Taxes, other than income	55,101	2,572	446	195	—	58,314
Total operating expenses	193,352	24,905	13,165	2,591	(509)	233,504
Operating income	173,728	34,329	10,379	8,025	86	226,547
Miscellaneous income (expense)	835	283	118	2,060	(4,861)	(1,565)
Interest charges	28,821	7,349	3,461	677	(4,775)	35,533
Income before income taxes	145,742	27,263	7,036	9,408	—	189,449
Income tax expense	44,166	7,798	3,688	4,794	—	60,446
Net income	$ 101,576	$19,465	$ 3,348	$ 4,614	$ —	$ 129,003
Capital expenditures	$ 84,618	$28,303	$ 88	$ 954	$ —	$ 113,963

	Three Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,521,636	$22,830	$ 931,990	$ 7,529	$ —	$2,483,985
Intersegment revenues	220	28,610	196,663	2,493	(227,986)	—
	1,521,856	51,440	1,128,653	10,022	(227,986)	2,483,985
Purchased gas cost	1,164,332	—	1,112,321	338	(227,400)	2,049,591
Gross profit	357,524	51,440	16,332	9,684	(586)	434,394
Operating expenses						
Operation and maintenance	98,578	15,086	5,525	1,536	(672)	120,053
Depreciation and amortization	43,130	4,907	374	379	—	48,790
Taxes, other than income	52,304	1,385	407	312	—	54,408
Total operating expenses	194,012	21,378	6,306	2,227	(672)	223,251
Operating income	163,512	30,062	10,026	7,457	86	211,143
Miscellaneous income	3,670	209	602	1,942	(4,956)	1,467
Interest charges	29,084	6,776	2,002	524	(4,870)	33,516
Income before income taxes	138,098	23,495	8,626	8,875	—	179,094
Income tax expense	52,442	8,271	3,347	3,500	—	67,560
Net income	$ 85,656	$15,224	$ 5,279	$ 5,375	$ —	$ 111,534
Capital expenditures	$ 89,671	$13,700	$ 38	$ 1,158	$ —	$ 104,567

	Six Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,285,968	$ 62,319	$1,165,980	$23,471	$ —	$3,537,738
Intersegment revenues	420	51,597	330,173	5,249	(387,439)	—
	2,286,388	113,916	1,496,153	28,720	(387,439)	3,537,738
Purchased gas cost	1,620,924	—	1,442,586	5,559	(386,594)	2,682,475
Gross profit	665,464	113,916	53,567	23,161	(845)	855,263
Operating expenses						
Operation and maintenance	188,704	44,896	20,839	3,073	(1,017)	256,495
Depreciation and amortization	94,680	9,961	797	1,138	—	106,576
Taxes, other than income	95,847	5,360	1,039	205	—	102,451
Total operating expenses	379,231	60,217	22,675	4,416	(1,017)	465,522
Operating income	286,233	53,699	30,892	18,745	172	389,741
Miscellaneous income (expense)	3,956	1,098	419	4,221	(11,560)	(1,866)
Interest charges	61,708	15,428	7,363	1,413	(11,388)	74,524
Income before income taxes	228,481	39,369	23,948	21,553	—	313,351
Income tax expense	76,772	12,243	10,025	9,345	—	108,385
Net income	$ 151,709	$ 27,126	$ 13,923	$12,208	$ —	$ 204,966
Capital expenditures	$ 173,621	$ 33,363	$ 117	$14,229	$ —	$ 221,330

	Six Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$2,449,665	$45,267	$1,634,712	$11,851	$ —	$4,141,495
Intersegment revenues	368	51,219	334,658	4,898	(391,143)	—
	2,450,033	96,486	1,969,370	16,749	(391,143)	4,141,495
Purchased gas cost	1,819,309	—	1,907,075	1,067	(389,988)	3,337,463
Gross profit	630,724	96,486	62,295	15,682	(1,155)	804,032
Operating expenses						
Operation and maintenance	195,825	30,518	13,402	2,824	(1,327)	241,242
Depreciation and amortization	85,962	9,823	761	757	—	97,303
Taxes, other than income	87,922	3,829	3,407	677	—	95,835
Total operating expenses	369,709	44,170	17,570	4,258	(1,327)	434,380
Operating income	261,015	52,316	44,725	11,424	172	369,652
Miscellaneous income	4,146	383	1,398	3,970	(8,523)	1,374
Interest charges	60,298	13,847	3,316	1,223	(8,351)	70,333
Income before income taxes	204,863	38,852	42,807	14,171	—	300,693
Income tax expense	79,043	13,781	16,928	5,604	—	115,356
Net income	$ 125,820	$25,071	$ 25,879	$ 8,567	$ —	$ 185,337
Capital expenditures	$ 173,984	$22,082	$ 69	$ 2,587	$ —	$ 198,722

Balance sheet information at March 31, 2009 and September 30, 2008 by segment is presented in the following tables:

	March 31, 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	$3,577,546	$608,118	$ 7,312	$ 70,216	$ —	$4,263,192
Investment in subsidiaries	484,117	—	(2,096)	—	(482,021)	—
Current assets						
Cash and cash equivalents	379,391	—	86,143	16,551	—	482,085
Assets from risk management activities	676	—	42,266	2,394	(3,623)	41,713
Other current assets	671,993	16,614	265,457	77,428	(76,735)	954,757
Intercompany receivables	504,887	—	—	147,783	(652,670)	—
Total current assets	1,556,947	16,614	393,866	244,156	(733,028)	1,478,555
Intangible assets	—	—	1,774	—	—	1,774
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	—	—	9,739	—	—	9,739
Deferred charges and other assets	166,610	7,924	873	20,096	—	195,503
	$6,355,140	$765,023	$435,750	$344,897	$(1,215,049)	$6,685,761
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,178,494	$157,270	$ 75,451	$251,396	$ (484,117)	$2,178,494
Long-term debt	2,168,683	—	—	458	—	2,169,141
Total capitalization	4,347,177	157,270	75,451	251,854	(484,117)	4,347,635
Current liabilities						
Current maturities of long-term debt	400,000	—	—	225	—	400,225
Short-term debt	—	—	60,000	—	(60,000)	—
Liabilities from risk management activities	22,535	—	6,734	1,200	(3,623)	26,846
Other current liabilities	586,656	6,850	203,044	76,973	(14,527)	858,996
Intercompany payables	—	525,249	127,421	—	(652,670)	—
Total current liabilities	1,009,191	532,099	397,199	78,398	(730,820)	1,286,067
Deferred income taxes	422,381	71,643	(37,586)	10,542	(112)	466,868
Noncurrent liabilities from risk management activities	4	—	13	—	—	17
Regulatory cost of removal obligation	313,486	—	—	—	—	313,486
Deferred credits and other liabilities	262,901	4,011	673	4,103	—	271,688
	$6,355,140	$765,023	$435,750	$344,897	$(1,215,049)	$6,685,761

	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

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 March 31, 2009, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2009 and 2008, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 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
April 30, 2009

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", "seek", "strategy" or similar 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 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 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.

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, 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 six months ended March 31, 2009.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands, except per share data)			
Operating revenues	$1,821,406	$2,483,985	$3,537,738	$4,141,495
Gross profit	460,051	434,394	855,263	804,032
Operating expenses	233,504	223,251	465,522	434,380
Operating income	226,547	211,143	389,741	369,652
Miscellaneous income (expense)	(1,565)	1,467	(1,866)	1,374
Interest charges	35,533	33,516	74,524	70,333
Income before income taxes	189,449	179,094	313,351	300,693
Income tax expense	60,446	67,560	108,385	115,356
Net income	$ 129,003	$ 111,534	$ 204,966	$ 185,337
Diluted net income per share	$ 1.41	$ 1.24	$ 2.24	$ 2.06

Our consolidated net income during the three and six months ended March 31, 2009 and 2008 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2009	2008	Change
		(In thousands)	
Natural gas distribution segment	$101,576	$ 85,656	$15,920
Regulated transmission and storage segment	19,465	15,224	4,241
Natural gas marketing segment	3,348	5,279	(1,931)
Pipeline, storage and other segment	4,614	5,375	(761)
Net income	$129,003	$111,534	$17,469

	Six Months Ended March 31		
	2009	2008	Change
		(In thousands)	
Natural gas distribution segment	$151,709	$125,820	$ 25,889
Regulated transmission and storage segment	27,126	25,071	2,055
Natural gas marketing segment	13,923	25,879	(11,956)
Pipeline, storage and other segment	12,208	8,567	3,641
Net income	$204,966	$185,337	$ 19,629

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

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$121,041	$100,880	$20,161
Nonregulated operations	7,962	10,654	(2,692)
Consolidated net income	$129,003	$111,534	$17,469
Diluted EPS from regulated operations	$ 1.32	$ 1.12	$ 0.20
Diluted EPS from nonregulated operations	0.09	0.12	(0.03)
Consolidated diluted EPS	$ 1.41	$ 1.24	$ 0.17

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$178,835	$150,891	$27,944
Nonregulated operations	26,131	34,446	(8,315)
Consolidated net income	$204,966	$185,337	$19,629
Diluted EPS from regulated operations	$ 1.96	$ 1.68	$ 0.28
Diluted EPS from nonregulated operations	0.28	0.38	(0.10)
Consolidated diluted EPS	$ 2.24	$ 2.06	$ 0.18

The following summarizes the results of our operations and other significant events for the six months ended March 31, 2009:

- Regulated operations generated 87 percent of our net income during the six months ended March 31, 2009 compared to 81 percent during the six months ended March 31, 2008. The $27.9 million increase in our regulated operations net income primarily reflects favorable ratemaking activity coupled with a one-time tax benefit discussed below.

- Nonregulated operations contributed 13 percent of net income during the six months ended March 31, 2009 compared to 19 percent during the six months ended March 31, 2008. The $8.3 million decrease in our nonregulated operations net income primarily reflects a decrease in unrealized margins and an increase in operating expenses partially offset by favorable asset optimization margins.

- For the six months ended March 31, 2009, we generated $614.6 million in operating cash flow compared with $479.2 million for the six months ended March 31, 2008, primarily reflecting 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 and the favorable timing of the recovery of gas costs.

- On March 23, 2009, we filed a $900 million shelf registration statement with the Securities and Exchange Commission (SEC) that replaced our previously existing shelf registration statement. On March 26, 2009, we completed an offering of $450 million unsecured 8.50% senior notes and received net proceeds of approximately $446 million. Most of the net proceeds received were used to repay our $400 million unsecured 4.00% senior notes, which were called on March 30, 2009 for redemption on April 30, 2009.

- Quarter-to-date and year-to-date results were favorably impacted by a one-time tax benefit of $11.3 million, or $0.12 per diluted share. The benefit arose during the quarter when we updated the tax rates used to record our deferred taxes. This benefit increased natural gas distribution net income by $10.5 million and regulated transmission and storage income by $1.7 million. However, net income for the natural gas marketing and pipeline, storage and other segments' net income were reduced by $0.3 million and $0.6 million.

Three Months Ended March 31, 2009 compared with Three Months Ended March 31, 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. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Prior to January 1, 2009, timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences could be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income. 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 still occurs 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.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$367,080	$357,524	$ 9,556
Operating expenses	193,352	194,012	(660)
Operating income	173,728	163,512	10,216
Miscellaneous income	835	3,670	(2,835)
Interest charges	28,821	29,084	(263)
Income before income taxes	145,742	138,098	7,644
Income tax expense	44,166	52,442	(8,276)
Net income	$101,576	$ 85,656	$ 15,920
Consolidated natural gas distribution sales volumes — MMcf	121,560	135,568	(14,008)
Consolidated natural gas distribution transportation volumes — MMcf	35,061	39,730	(4,669)
Total consolidated natural gas distribution throughput — MMcf	156,621	175,298	(18,677)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.48	$ 0.44	$ 0.04
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.10	$ 8.59	$ (1.49)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended March 31, 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 March 31		
	2009	2008	Change
		(In thousands)	
Mid-Tex	$ 80,374	$ 72,479	$ 7,895
Kentucky/Mid-States	27,404	29,875	(2,471)
Louisiana	19,782	19,236	546
West Texas	14,806	8,919	5,887
Mississippi	16,771	16,514	257
Colorado-Kansas	13,623	15,536	(1,913)
Other	968	953	15
Total	$173,728	$163,512	$10,216

The $9.6 million increase in natural gas distribution gross profit primarily reflects a net $21.9 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $16.5 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 $5.4 million increase in rate adjustments primarily in Georgia, Louisiana and West Texas. The increase also reflects the reversal of a $7.0 million accrual for estimated unrecoverable gas costs recorded in a prior year. These increases in gross profit were partially offset by a $13.5 million decrease as a result of an 11 percent decrease in distribution throughput, primarily associated with lower residential and commercial 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 $8.9 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This decrease was partially offset by a $0.8 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 an $8.1 million decrease 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 and taxes, other than income, decreased $0.7 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $6.9 million, primarily due to lower legal, fuel and other administrative costs.

Depreciation and amortization expense increased $4.4 million for the second quarter of fiscal 2009 compared with second quarter of fiscal 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Results for the quarter include the aforementioned $10.5 million tax benefit, which more than offset the decrease attributable to the absence in the current-year quarter of a $1.2 million gain on the sale of irrigation assets in our West Texas Division in the prior-year quarter.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 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 RRM with the Settled Cities. The filing requested an increase in operating income of $9.7 million for the Settled Cities. Representatives of the Settled Cities are currently reviewing the filing and a final determination is expected in July 2009. Beginning in November 2008, rates were implemented from our first RRM filing with the Settled Cities, which resulted in an increase in 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 operating income of $11.1 million. Representatives of the West Texas Cities are currently reviewing the filing and a final determination is expected 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 9½ 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 operating income of $3.5 million. The City of Lubbock 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 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 requesting an increase in operating income of $3.9 million. The filing was for the test year ended December 31, 2008. We anticipate final resolution of this proceeding by June 2009.

In September 2008, we filed our Mississippi stable rate filing with the Mississippi Public Service Commission (MPSC) requesting an increase 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 has until July 10, 2009 to either accept or object to the filing. If this filing is accepted, the rates will go into 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 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 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 operating income for customers within the City of Dallas by $9.1 million. The City of Dallas suspended the filing on December 10, 2008 and denied the increase in March 2009. The Company has appealed the filing and in April 2009 we requested an increase in operating income of $7.5 million and concurrently filed for a statement of intent to increase operating income $1.3 million applicable to the Mid-Tex unincorporated areas. A final ruling by the Railroad Commission of Texas (RRC) is expected by October 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.

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

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.

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.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 27,061	$ 28,260	$ (1,199)
Third-party transportation	23,846	18,229	5,617
Storage and park and lend services	2,657	1,862	795
Other	5,670	3,089	2,581
Gross profit	59,234	51,440	7,794
Operating expenses	24,905	21,378	3,527
Operating income	34,329	30,062	4,267
Miscellaneous income	283	209	74
Interest charges	7,349	6,776	573
Income before income taxes	27,263	23,495	3,768
Income tax expense	7,798	8,271	(473)
Net income	$ 19,465	$ 15,224	$ 4,241
Gross pipeline transportation volumes — MMcf	193,356	223,476	(30,120)
Consolidated pipeline transportation volumes — MMcf	123,285	141,108	(17,823)

The $7.8 million increase in gross profit was attributable primarily to a $3.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions and a $3.3 million increase from higher demand-based fees. The improvement in gross profit also reflects a $2.9 million gain on the routine sale of excess gas during the quarter and a $1.4 million increase due to our 2006 and 2007 GRIP filings. These increases were partially offset by a $4.1 million decrease arising from lower city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $3.5 million primarily due to increased employee and pipeline maintenance costs.

Results for the quarter also include the aforementioned $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

Recent Ratemaking Developments

In February 2009, the Atmos Pipeline — Texas Division made a GRIP filing seeking an increase in 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 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 March 31, 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 unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 23,165	$ 26,195	$ (3,030)
Asset optimization	(2,073)	27,737	(29,810)
	21,092	53,932	(32,840)
Unrealized margins	2,452	(37,600)	40,052
Gross profit	23,544	16,332	7,212
Operating expenses	13,165	6,306	6,859
Operating income	10,379	10,026	353
Miscellaneous income	118	602	(484)
Interest charges	3,461	2,002	1,459
Income before income taxes	7,036	8,626	(1,590)
Income tax expense	3,688	3,347	341
Net income	$ 3,348	$ 5,279	$ (1,931)
Gross natural gas marketing sales volumes — MMcf	123,066	136,677	(13,611)
Consolidated natural gas marketing sales volumes — MMcf	104,973	120,023	(15,050)
Net physical position (Bcf)	21.9	20.7	1.2

The $7.2 million increase in our natural gas marketing segment's gross profit was driven primarily by a $40.1 million increase in unrealized margins. This increase 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.

The increase in unrealized margins was partially offset by a $29.8 million decrease in asset optimization margins. During the current quarter, as a result of falling current cash prices, AEM elected to defer storage withdrawals, reset the corresponding financial instruments and inject additional gas into storage to increase the potential gross profit it could realize in future periods from its asset optimization activities. Accordingly, AEM's results for the quarter reflect lower realized gains from storage withdrawals and the settlement of the associated financial instruments. In the prior-year quarter, AEM elected to withdraw storage and realize the corresponding storage withdrawal gains.

In addition, delivered gas margins decreased $3.0 million compared with the prior-year quarter largely attributable to a 10 percent decrease in gross sales volumes, primarily associated with lower industrial demand due to the current economic climate. Per-unit margins for the quarter were approximately two percent lower compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $6.9 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 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 March 31, 2009, December 31, 2008 and September 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)
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

(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 March 31, 2009, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $33.4 million. This amount will be reduced by $2.4 million of net unrealized gains recorded in the financial statements as of March 31, 2009 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit was $31.0 million at March 31, 2009.

During the six months ended March 31, 2009, AEM increased its potential gross profit by $18.9 million to $31.0 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 13.9 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, but higher than the economic gross profit of $10.8 million as of March 31, 2008. This decrease from September 2008 to March 2009 was partially offset by lower unrealized gains associated with these positions primarily due to lower current cash 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 March 31, 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 March 31, 2009, without encountering operational or other issues, we anticipate that approximately $1 million of the potential gross profit as of March 31, 2009 will be recognized in fiscal 2009 with the remaining $30 million expected to be recognized during the first six months of fiscal 2010.

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 March 31, 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 March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Asset optimization	$15,157	$ 6,604	$ 8,553
Storage and transportation services	3,312	3,895	(583)
Other	350	1,113	(763)
Unrealized margins	(8,203)	(1,928)	(6,275)
Gross profit	10,616	9,684	932
Operating expenses	2,591	2,227	364
Operating income	8,025	7,457	568
Miscellaneous income	2,060	1,942	118
Interest charges	677	524	153
Income before income taxes	9,408	8,875	533
Income tax expense	4,794	3,500	1,294
Net income	$ 4,614	$ 5,375	$ (761)

Gross profit from our pipeline, storage and other segment increased $0.9 million primarily due to an $8.6 million increase in asset optimization margins resulting from larger realized gains from the settlement of financial positions associated with storage and trading activities and basis gains earned from utilizing controlled pipeline capacity. These increases were partially offset by a $6.3 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 March 31, 2009 were consistent with the prior-year quarter.

Six Months Ended March 31, 2009 compared with Six Months Ended March 31, 2008

Natural Gas Distribution Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$665,464	$630,724	$ 34,740
Operating expenses	379,231	369,709	9,522
Operating income	286,233	261,015	25,218
Miscellaneous income	3,956	4,146	(190)
Interest charges	61,708	60,298	1,410
Income before income taxes	228,481	204,863	23,618
Income tax expense	76,772	79,043	(2,271)
Net income	$151,709	$125,820	$ 25,889
Consolidated natural gas distribution sales volumes — MMcf	213,006	220,335	(7,329)
Consolidated natural gas distribution transportation volumes — MMcf	69,397	73,479	(4,082)
Total consolidated natural gas distribution throughput — MMcf	282,403	293,814	(11,411)
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	$ 7.61	$ 8.26	$ (0.65)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the six months ended March 31, 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.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$133,052	$122,704	$10,348
Kentucky/Mid-States	46,429	44,043	2,386
Louisiana	34,366	31,168	3,198
West Texas	22,819	13,895	8,924
Mississippi	25,206	24,343	863
Colorado-Kansas	22,224	22,224	—
Other	2,137	2,638	(501)
Total	$286,233	$261,015	$25,218

The $34.7 million increase in natural gas distribution gross profit primarily reflects a net $37.2 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $27.8 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 $9.4 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 an $8.3 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 a $14.8 million decrease as a result of a four percent decrease in distribution throughput primarily associated with lower residential and commercial 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 $9.2 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, combined with a $7.3 million period-over-period increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $16.5 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 and taxes, other than income, increased $9.5 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $4.7 million, primarily due to lower legal, fuel and other administrative costs. These decreases were partially offset by a $2.1 million noncash charge in the first quarter of fiscal 2009 to impair certain available-for-sale investments due to the recent deterioration of the financial markets.

Depreciation and amortization expense increased $8.7 million for the current-year period compared with six months ended March 31, 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 $1.4 million due to higher average short-term debt balances, interest rates and commitment fees experienced during the current-year period compared to the prior-year period. These increases are associated with the recent adverse conditions in the credit markets.

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

Regulated Transmission and Storage Segment

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 51,413	$ 50,648	$ 765
Third-party transportation	49,212	36,461	12,751
Storage and park and lend services	5,014	3,901	1,113
Other	8,277	5,476	2,801
Gross profit	113,916	96,486	17,430
Operating expenses	60,217	44,170	16,047
Operating income	53,699	52,316	1,383
Miscellaneous income	1,098	383	715
Interest charges	15,428	13,847	1,581
Income before income taxes	39,369	38,852	517
Income tax expense	12,243	13,781	(1,538)
Net income	$ 27,126	$ 25,071	$ 2,055
Gross pipeline transportation volumes — MMcf	385,528	412,340	(26,812)
Consolidated pipeline transportation volumes — MMcf	259,143	277,308	(18,165)

The $17.4 million increase in gross profit was attributable primarily to a $7.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions and a $6.4 million increase from higher demand-based fees. The improvement in gross profit also reflects a $2.9 million gain on the sale of excess gas during the current-year period and a $2.7 million increase due to our 2006 and 2007 GRIP filings. These increases were partially offset by a $3.4 million decrease associated with lower city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $16.0 million primarily due to increased employee and pipeline maintenance costs.

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

Natural Gas Marketing Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 41,718	$ 44,368	$ (2,650)
Asset optimization	34,866	27,212	7,654
	76,584	71,580	5,004
Unrealized margins	(23,017)	(9,285)	(13,732)
Gross profit	53,567	62,295	(8,728)
Operating expenses	22,675	17,570	5,105
Operating income	30,892	44,725	(13,833)
Miscellaneous income	419	1,398	(979)
Interest charges	7,363	3,316	4,047
Income before income taxes	23,948	42,807	(18,859)
Income tax expense	10,025	16,928	(6,903)
Net income	$ 13,923	$ 25,879	$(11,956)
Gross natural gas marketing sales volumes — MMcf	233,724	245,386	(11,662)
Consolidated natural gas marketing sales volumes — MMcf	198,281	216,229	(17,948)
Net physical position (Bcf)	21.9	20.7	1.2

The $8.7 million decrease in our natural gas marketing segment's gross profit was driven primarily by a $13.7 million decrease in unrealized margins. This decrease reflects higher volatility during the current 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 decreased by $2.7 million. The decrease was largely attributable to a five percent decrease in gross sales volumes primarily associated with lower industrial demand due to the current economic climate combined with a one percent decrease in per-unit margins, compared with the prior-year period.

The decrease in unrealized margins and delivered gas margins was partially offset by a $7.7 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 the margin loss incurred in the second quarter 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.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $5.1 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.

Pipeline, Storage and Other Segment

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
		(In thousands)	
Asset optimization	$20,624	$ 6,374	$14,250
Storage and transportation services	6,627	7,023	(396)
Other	1,339	1,840	(501)
Unrealized margins	(5,429)	445	(5,874)
Gross profit	23,161	15,682	7,479
Operating expenses	4,416	4,258	158
Operating income	18,745	11,424	7,321
Miscellaneous income	4,221	3,970	251
Interest charges	1,413	1,223	190
Income before income taxes	21,553	14,171	7,382
Income tax expense	9,345	5,604	3,741
Net income	$12,208	$ 8,567	$ 3,641

Gross profit from our pipeline, storage and other segment increased $7.5 million primarily due to a $14.3 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 $5.9 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 six months ended March 31, 2009 were consistent with the prior-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 March 31, 2009, there were no borrowings or commercial paper outstanding under this facility and $566.7 million was available.

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, which, on March 30, 2009, were called for redemption 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 will be used for general corporate purposes.

During the six months ended March 31, 2009, we increased 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. 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 will have a total of approximately $1.3 billion available to us under four committed credit facilities beginning April 1, 2009. As of March 31, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $998 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 six months ended March 31, 2009, we generated operating cash flow of $614.6 million from operating activities compared with $479.2 million for the six months ended March 31, 2008. Period over period, the $135.4 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 $61.2 million, coupled with a $51.9 million increase due to the favorable timing in the recovery of gas costs during 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, 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 six months ended March 31, 2009, capital expenditures were $221.3 million compared with $198.7 million for the six months ended March 31, 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 six months ended March 31, 2009, our financing activities provided $46.0 million compared with a use of cash of $198.4 million in the prior-year period. Our significant financing activities for the six months ended March 31, 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, which were called on March 30, 2009 for redemption on April 30, 2009.
- During the six months ended March 31, 2009, we decreased our borrowings by a net $353.5 million under our short-term credit facilities compared with $150.6 million in the prior-year period. The reduction in the net borrowings reflects the timing of the use of our line of credit to finance natural gas purchases and working capital.
- We repaid $0.6 million of long-term debt during the six months ended March 31, 2009 compared with $2.3 million during the six months ended March 31, 2008. Payments in both periods reflected regularly scheduled payments in accordance with our various debt agreements.
- During the six months ended March 31, 2009, we paid $60.4 million in cash dividends compared with $58.4 million for the six months ended March 31, 2008. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.65 per share during the six months ended March 31, 2008 to $0.66 per share during the six months ended March 31, 2009 combined with new share issuances under our various equity plans.
- During the six months ended March 31, 2009, we issued 0.6 million shares of common stock under our various equity plans, which generated net proceeds of $12.4 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 six months ended March 31, 2009 and 2008.

	Six Months Ended March 31	
	2009	2008
Shares issued:		
Direct Stock Purchase Plan	220,361	203,025
Retirement Savings Plan and Trust	330,990	268,712
1998 Long-Term Incentive Plan	579,990	343,500
Outside Directors Stock-for-Fee Plan	1,590	1,602
Total shares issued	1,132,931	816,839

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 $1.2 billion of working capital funding. As of March 31, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $998 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, which were called on March 30, 2009 for redemption on April 30, 2009.

As of March 31, 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 credit rating from BBB to BBB+ and affirmed a stable outlook. 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. Additionally, our credit rating is currently under review for a possible upgrade by Moody's. 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+	Baa3	BBB+
Commercial paper	A-2	P-3	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 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 March 31, 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 as of March 31, 2009, September 30, 2008 and March 31, 2008:

	March 31, 2009		September 30, 2008		March 31, 2008	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 350,542	7.7%	$ —	—%
Long-term debt	2,569,366	54.1%	2,120,577	46.9%	2,128,149	50.0%
Shareholders' equity	2,178,494	45.9%	2,052,492	45.4%	2,125,993	50.0%
Total capitalization	$4,747,860	100.0%	$4,523,611	100.0%	$4,254,142	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 54.1 percent at March 31, 2009, 54.6 percent at September 30, 2008 and 50.0 percent at March 31, 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. The increase in the debt to capital ratio compared to March 31, 2008 is due to the timing of the repayment of our $400 million unsecured 4.00% unsecured senior notes. Had we repaid the notes as of March 31, 2009, our total-debt-to-capital ratio would have been 49.9 percent. 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 six months ended March 31, 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. We have filed a 7C application with 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 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 six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(51,314)	$(21,528)	$ (63,677)	$(21,053)
Contracts realized/settled	(47,231)	(4,972)	(100,996)	(27,310)
Fair value of new contracts	277	1,401	(4,006)	(280)
Other changes in value	76,405	34,604	146,816	58,148
Fair value of contracts at end of period	$(21,863)	$ 9,505	$ (21,863)	$ 9,505

The fair value of our natural gas distribution segment's financial instruments at March 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 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	$(21,859)	$(4)	$—	$—	$(21,863)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(21,859)	$(4)	$—	$—	$(21,863)

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 six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(28,598)	$ 51,859	$ 16,542	$ 26,808
Contracts realized/settled	6,972	(46,331)	(13,275)	(41,256)
Fair value of new contracts	—	—	—	—
Other changes in value	(11,020)	(28,503)	(35,913)	(8,527)
Fair value of contracts at end of period	(32,646)	(22,975)	(32,646)	(22,975)
Netting of cash collateral	79,098	29,591	79,098	29,591
Cash collateral and fair value of contracts at period end	$ 46,452	$ 6,616	$ 46,452	$ 6,616

The fair value of our natural gas marketing segment's financial instruments at March 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 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	$(42,372)	$9,726	$—	$—	$(32,646)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(42,372)	$9,726	$—	$—	$(32,646)

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 six months ended March 31, 2009 and 2008, our total net periodic pension and other benefits cost was $24.1 million and $23.9 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 expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009. The need for this funding reflects 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 will increase 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 $10 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.

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 six-month periods ended March 31, 2009 and 2008.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
METERS IN SERVICE, end of period				
Residential	2,937,865	2,933,980	2,937,865	2,933,980
Commercial	274,449	275,998	274,449	275,998
Industrial	2,212	2,269	2,212	2,269
Public authority and other	9,243	8,948	9,243	8,948
Total meters	3,223,769	3,221,195	3,223,769	3,221,195
INVENTORY STORAGE BALANCE — Bcf	31.9	34.4	31.9	34.4
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	74,467	83,934	128,675	132,965
Commercial	36,689	40,506	65,018	67,126
Industrial	5,758	7,258	11,158	13,212
Public authority and other	4,646	3,870	8,155	7,032
Total gas sales volumes	121,560	135,568	213,006	220,335
Transportation volumes	36,169	40,938	71,454	75,791
Total throughput	157,729	176,506	284,460	296,126
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$ 785,456	$ 971,673	$1,432,556	$1,525,962
Commercial	334,815	421,708	637,509	690,177
Industrial	46,259	62,135	96,414	113,311
Public authority and other	36,991	37,244	68,385	67,848
Total gas sales revenues	1,203,521	1,492,760	2,234,864	2,397,298
Transportation revenues	16,889	17,786	32,655	32,791
Other gas revenues	10,010	11,310	18,869	19,944
Total operating revenues	$1,230,420	$1,521,856	$2,286,388	$2,450,033
Average transportation revenue per Mcf	$ 0.47	$ 0.43	$ 0.46	$ 0.43
Average cost of gas per Mcf sold	$ 7.10	$ 8.59	$ 7.61	$ 8.26

See footnote following these tables.

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

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
CUSTOMERS, end of period				
Industrial	698	716	698	716
Municipal	61	61	61	61
Other	527	474	527	474
Total	1,286	1,251	1,286	1,251
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	20.4	19.6	20.4	19.6
Pipeline, storage and other	2.0	1.2	2.0	1.2
Total	22.4	20.8	22.4	20.8
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	193,356	223,476	385,528	412,340
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	123,066	136,677	233,724	245,386
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 59,234	$ 51,440	$ 113,916	$ 96,486
Natural gas marketing	708,658	1,128,653	1,496,153	1,969,370
Pipeline, storage and other	12,272	10,022	28,720	16,749
Total operating revenues	$780,164	$1,190,115	$1,638,789	$2,082,605

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 year ended September 30, 2008. During the six months ended March 31, 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 March 31, 2009 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the

SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 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 six months ended March 31, 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 4. *Submission of Matters to a Vote of Security Holders*

At the Annual Meeting of Shareholders of Atmos Energy Corporation on February 4, 2009, 79,385,275 votes were cast as follows:

	Votes For	Votes Withheld/ Against	Votes Abstaining
Class I Director:			
Ruben E. Esquivel	77,254,669	2,130,606	—
Class II Directors:			
Richard W. Cardin	77,675,895	1,709,380	—
Thomas C. Meredith	77,720,662	1,664,613	—
Nancy K. Quinn	78,057,677	1,327,598	—
Stephen R. Springer	77,027,075	2,358,200	—
Richard Ware II	77,735,952	1,649,323	—
Ratification of the Audit Committee's engagement of Ernst & Young LLP to serve as the Company's registered independent public accounting firm for fiscal year 2009	78,424,677	767,618	192,980
Shareholder proposal regarding declassification of the Board of Directors	45,212,206	17,596,650	527,384

Mr. Dan Busbee, a Class I director, retired on February 4, 2009, at the conclusion of the Annual Meeting of Shareholders, in accordance with the Board's mandatory retirement policy. The remaining directors will continue to serve until the expiration of their terms. The term of the Class I directors, Travis W. Bain II, Richard W. Douglas, Ruben E. Esquivel and Richard K. Gordon, will expire in 2011. The term of the Class II directors, Richard W. Cardin, Thomas C. Meredith, Nancy K. Quinn, Stephen R. Springer and Richard Ware II, will expire in 2012. The term of the Class III directors, Robert W. Best, Thomas J. Garland, Phillip E. Nichol and Charles K. Vaughan, will expire in 2010.

Item 6. *Exhibits*

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

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: May 1, 2009

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number
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.

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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2008

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of January 27, 2009.

Class	Shares Outstanding
No Par Value	91,634,602

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.
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
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

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2008	September 30, 2008
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,803,491	$5,730,156
Less accumulated depreciation and amortization	1,608,743	1,593,297
Net property, plant and equipment	4,194,748	4,136,859
Current assets		
Cash and cash equivalents	69,799	46,717
Accounts receivable, net	833,125	477,151
Gas stored underground	582,743	576,617
Other current assets	197,441	184,619
Total current assets	1,683,108	1,285,104
Goodwill and intangible assets	738,929	739,086
Deferred charges and other assets	202,114	225,650
	$6,818,899	$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: December 31, 2008 — 91,599,495 shares; September 30, 2008 — 90,814,683 shares	$ 458	$ 454
Additional paid-in capital	1,757,834	1,744,384
Retained earnings	381,633	343,601
Accumulated other comprehensive loss	(61,849)	(35,947)
Shareholders' equity	2,078,076	2,052,492
Long-term debt	1,719,920	2,119,792
Total capitalization	3,797,996	4,172,284
Current liabilities		
Accounts payable and accrued liabilities	815,095	395,388
Other current liabilities	441,481	460,372
Short-term debt	360,833	350,542
Current maturities of long-term debt	400,507	785
Total current liabilities	2,017,916	1,207,087
Deferred income taxes	431,324	441,302
Regulatory cost of removal obligation	305,784	298,645
Deferred credits and other liabilities	265,879	267,381
	$6,818,899	$6,386,699

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2008	2007
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,055,968	$ 928,177
Regulated transmission and storage segment	54,682	45,046
Natural gas marketing segment	787,495	840,717
Pipeline, storage and other segment	16,448	6,727
Intersegment eliminations	(198,261)	(163,157)
	1,716,332	1,657,510
Purchased gas cost		
Natural gas distribution segment	757,584	654,977
Regulated transmission and storage segment	—	—
Natural gas marketing segment	757,472	794,754
Pipeline, storage and other segment	3,903	729
Intersegment eliminations	(197,839)	(162,588)
	1,321,120	1,287,872
Gross profit	395,212	369,638
Operating expenses		
Operation and maintenance	134,755	121,189
Depreciation and amortization	53,126	48,513
Taxes, other than income	44,137	41,427
Total operating expenses	232,018	211,129
Operating income	163,194	158,509
Miscellaneous expense	(301)	(93)
Interest charges	38,991	36,817
Income before income taxes	123,902	121,599
Income tax expense	47,939	47,796
Net income	$ 75,963	$ 73,803
Basic net income per share	$ 0.84	$ 0.83
Diluted net income per share	$ 0.83	$ 0.82
Cash dividends per share	$ 0.330	$ 0.325
Weighted average shares outstanding:		
Basic	90,471	89,006
Diluted	91,066	89,608

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2008	2007
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 75,963	$ 73,803
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	53,126	48,513
Charged to other accounts	8	23
Deferred income taxes	27,175	11,978
Other	7,683	4,406
Net assets / liabilities from risk management activities	(22,793)	16,883
Net change in operating assets and liabilities	9,553	(94,169)
Net cash provided by operating activities	150,715	61,437
Cash Flows From Investing Activities		
Capital expenditures	(107,367)	(94,155)
Other, net	(1,210)	(1,874)
Net cash used in investing activities	(108,577)	(96,029)
Cash Flows From Financing Activities		
Net increase in short-term debt	5,312	50,690
Repayment of long-term debt	(278)	(1,741)
Cash dividends paid	(30,165)	(29,178)
Issuance of common stock	6,075	5,970
Net cash provided by (used in) financing activities	(19,056)	25,741
Net increase (decrease) in cash and cash equivalents	23,082	(8,851)
Cash and cash equivalents at beginning of period	46,717	60,725
Cash and cash equivalents at end of period	$ 69,799	$ 51,874

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2008

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 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.

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS) and Atmos Power Systems, Inc., which are wholly owned by AEH. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, APS manages our natural gas gathering operations. These operations did not significantly impact our financial results for the period ended December 31, 2008. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles in the United States.

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 three-month period ended December 31, 2008 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 were no changes to those policies. However, during the three months ended December 31, 2008, we recognized a non-recurring $8.1 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.

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*. Except for the adoption of these accounting pronouncements, which are further discussed below, there were no significant changes to our accounting policies during the three months ended December 31, 2008.

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 its projected benefit obligation, fair value of plan assets and its 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.

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.

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 December 31, 2008 and September 30, 2008 included the following:

	December 31, 2008	September 30, 2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 90,394	$100,563
Merger and integration costs, net	7,480	7,586
Deferred gas costs	122,524	55,103
Environmental costs	888	980
Rate case costs	11,243	12,885
Deferred franchise fees	627	651
Deferred income taxes, net	343	343
Other	7,294	8,120
	$240,793	$186,231
Regulatory liabilities:		
Deferred gas costs	$ 68,226	$ 76,979
Regulatory cost of removal obligation	323,517	317,273
Other	5,569	5,639
	$397,312	$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.

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month periods ended December 31, 2008 and 2007:

	Three Months Ended December 31	
	2008	2007
	(In thousands)	
Net income	$ 75,963	$73,803
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(3,330) and $714	(5,433)	1,165
Other than temporary impairment of investments, net of tax expense of $790	1,288	—
Amortization of interest rate hedging transactions, net of tax expense of $482 and $482	787	787
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(13,817) and $4,937	(22,544)	8,053
Comprehensive income	$ 50,061	$83,808

Accumulated other comprehensive loss, net of tax, as of December 31, 2008 and September 30, 2008 consisted of the following unrealized gains (losses):

	December 31, 2008	September 30, 2008
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains (losses) on investments	$ (3,235)	$ 910
Treasury lock agreements	(10,317)	(11,104)
Cash flow hedges	(48,297)	(25,753)
	$(61,849)	$(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 an independent counterparty. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment. On a consolidated basis, these financial instruments are reported in the natural gas marketing 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 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 anticipate hedging approximately 29 percent, or 25,450 MMcf of the anticipated 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 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 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. 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.

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. Future 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 54 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 (1) the amount of unrealized gain or loss that has been reclassified from AOCI when the hedged volumes are sold and (2) 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.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges 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. Our risk management 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. We 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 December 31, 2008, AEH had a net open position (including existing storage) of 0.1 Bcf.

Interest Rate Risk Management Activities

Currently, we are not managing interest rate risk with financial instruments. However, in prior years, we periodically 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 as a component of interest expense through fiscal 2017.

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 December 31, 2008, our financial instruments were comprised of both long and short commodity positions, whereby a long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2008, 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	—	(13,655)	(1,883)
	Cash Flow	—	44,641	(3,390)
	Not designated	14,314	51,467	1,428
		14,314	82,453	(3,845)

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 December 31, 2008 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 $75.8 million and $56.6 million of cash held on deposit in margin accounts as of December 31, 2008 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 not agree with the amounts presented on our condensed consolidated balance sheet, nor will they agree 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)	
December 31, 2008:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 115,937	$ 115,937
Noncurrent commodity contracts	Deferred charges and other assets	—	10,678	10,678
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(145,464)	(145,464)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,246)	(1,246)
Total		—	(20,095)	(20,095)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	—	252,168	252,168
Noncurrent commodity contracts	Deferred charges and other assets	19	44,524	44,543
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(47,448)	(264,359)	(311,807)
Noncurrent commodity contracts	Deferred credits and other liabilities	(3,885)	(40,836)	(44,721)
Total		(51,314)	(8,503)	(59,817)
Total Financial Instruments		$(51,314)	$ (28,598)	$ (79,912)

(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	$ —	$ 110,696	$ 110,696
Noncurrent commodity contracts	Deferred charges and other assets	—	4,984	4,984
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(98,900)	(98,900)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(206)	(206)
Total		—	16,574	16,574
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	—	115,200	115,200
Noncurrent commodity contracts	Deferred charges and other assets	—	7,071	7,071
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(58,566)	(115,337)	(173,903)
Noncurrent commodity contracts	Deferred credits and other liabilities	(5,111)	(6,966)	(12,077)
Total		(63,677)	(32)	(63,709)
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.

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 months ended December 31, 2008 and 2007.

Unrealized margins recorded in our natural gas marketing and pipeline, storage and other segments are comprised of various components, including, but not limited to, unrealized gains and losses arising from hedge ineffectiveness. Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative instrument and the hedged item and could materially affect our results of operations for the reported period. For the three months ended December 31, 2008 and 2007 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $20.4 million and $38.8 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below. Although these unrealized gains and losses are currently recorded in our income statement, they are not necessarily indicative of the economic gross profit we anticipate realizing when the underlying physical and financial transactions are settled.

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 months ended December 31, 2008 and 2007 is presented below.

	Three Months Ended December 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 25,683	$ 3,939	$ 29,622
Fair value adjustment for natural gas inventory designated as the hedged item	(11,860)	(1,553)	(13,413)
Total impact on revenue	$ 13,823	$ 2,386	$ 16,209
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 1,952	$ —	$ 1,952
Timing ineffectiveness	11,871	2,386	14,257
	$ 13,823	$ 2,386	$ 16,209

	Three Months Ended December 31, 2007		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$17,227	$2,123	$19,350
Fair value adjustment for natural gas inventory designated as the hedged item	17,601	1,057	18,658
Total impact on revenue	$34,828	$3,180	$38,008
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 1,956	$ —	$ 1,956
Timing ineffectiveness	32,872	3,180	36,052
	$34,828	$3,180	$38,008

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.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statement for the three months ended December 31, 2008 and 2007 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 December 31, 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	$ —	$(28,244)	$7,968	$(20,276)
Gain arising from ineffective portion of commodity contracts	—	4,192	—	4,192
Total impact on revenue	—	(24,052)	7,968	(16,084)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(24,052)	$7,968	$(17,353)

	Three Months Ended December 31, 2007			
	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	$ —	$(9,254)	$425	$(8,829)
Gain arising from ineffective portion of commodity contracts	—	759	—	759
Total impact on revenue	—	(8,495)	425	(8,070)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(8,495)	$425	$(9,339)

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 months ended December 31, 2008 and 2007. 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 December 31	
	2008	2007
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ —	$ —
Forward commodity contracts	(35,115)	2,579
Recognition of losses in earnings due to settlements:		
Treasury lock agreements	787	787
Forward commodity contracts	12,571	5,474
Total other comprehensive income (loss) from hedging, net of tax[1]	$(21,757)	$8,840

[1] Utilizing an income tax rate of approximately 38 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 December 31, 2008:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$ (2,908)	$(45,271)	$(48,179)
Thereafter	(7,409)	(3,026)	(10,435)
Total[1]	$(10,317)	$(48,297)	$(58,614)

(1) Utilizing an income tax rate of approximately 38 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statement for the three months ended December 31, 2008 and 2007 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 December 31	
	2008	2007
	(In thousands)	
Natural gas marketing commodity contracts	$(3,832)	$ 326
Pipeline, storage and other commodity contracts	(83)	(644)
Total impact on revenue	$(3,915)	$(318)

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 in the following areas:

- 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 to these nonfinancial areas 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, and the adoption of this standard did not affect these valuations. 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' 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.

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.

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

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 December 31, 2008. 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 of Cash Collateral[1]	December 31, 2008
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 19	$ —	$ —	$ 19
Natural gas marketing segment	—	39,031	—	14,258	53,289
Total financial instruments	—	39,050	—	14,258	53,308
Hedged portion of gas stored underground					
Natural gas marketing segment	71,478	—	—	—	71,478
Pipeline, storage and other segment[2]	6,812	—	—	—	6,812
Total gas stored underground	78,290	—	—	—	78,290
Available-for-sale securities	27,983	—	—	—	27,983
Total assets	$106,273	$39,050	$ —	$ 14,258	$159,581
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,333	$ —	$ —	$ 51,333
Natural gas marketing segment	61,567	6,062	—	(61,567)	6,062
Total liabilities	$ 61,567	$57,395	$ —	$(61,567)	$ 57,395

(1) As of December 31, 2008, we had $75.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $61.6 million was used to offset financial instruments in a liability position. The remaining $14.2 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.

Our long-term debt, including current maturities, is recorded on our balance sheet at carrying value. However, SFAS 107, *Disclosures about Fair Value of Financial Instruments,* requires disclosure concerning the fair value of our debt. 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 December 31, 2008:

	December 31, 2008
	(In thousands)
Carrying Amount	$2,123,334
Fair Value	$1,773,869

The fair value as of December 31, 2008 was calculated utilizing discount rates ranging from 6.8 percent to 9.4 percent, remaining average maturities ranging from one to 26 years, and a credit adjustment of 6.4 percent.

5. Debt

Long-term debt

Long-term debt at December 31, 2008 and September 30, 2008 consisted of the following:

	December 31, 2008	September 30, 2008
	(In thousands)	
Unsecured 4.00% Senior Notes, due October 2009	$ 400,000	$ 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 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 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	1,031	1,309
Total long-term debt	2,123,334	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(2,907)	(3,035)
Current maturities	(400,507)	(785)
	$1,719,920	$2,119,792

As noted above, our unsecured 4.00% senior notes will mature in October 2009; accordingly, they have been classified within the current maturities of long-term debt. We are currently evaluating alternatives to refinance this debt, and we believe this refinancing effort will be successful.

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 reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $600 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide $1.2 billion of working capital funding. At December 31, 2008, there was $360.8 million of short-term debt outstanding, comprised of $202.9 million under our bank credit facilities and $157.9 million outstanding under our commercial paper program. 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 $600 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. At December 31, 2008, the total amount used under this facility was $360.8 million and $205.9 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 December 31, 2008, there were no borrowings outstanding under this facility.

The third facility is an $18 million unsecured facility expiring in March 2009 that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At December 31, 2008, 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 December 31, 2008, our total-debt-to-total-capitalization ratio, as defined, was 57 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 had 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. There was $40.9 million outstanding under this facility at December 31, 2008. 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.

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.

The amended facility also provides the ability for AEM to increase the borrowing base up to a maximum of $450 million, subject to the approval of the participating banks; 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.

AEM will use 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 December 31, 2008, there were no borrowings outstanding under this credit facility. However, at December 31, 2008, AEM letters of credit totaling $100.0 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 $177.8 million at December 31, 2008.

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 December 31, 2008, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.48 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 December 31, 2008, AEM's net working capital was $215.2 million and its tangible net worth was $240.2 million.

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. There were no borrowings outstanding under this facility at December 31, 2008. 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.

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. There were no borrowings outstanding under this facility at December 31, 2008. 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.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities. As of December 31, 2008, we had approximately $450 million of availability remaining under the registration statement. Due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $200 million of equity securities and $250 million of senior debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until we received an investment grade rating from all of the three credit rating agencies.

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 December 31, 2008. If we were unable to comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

Basic and diluted earnings per share for the three months ended December 31, 2008 and 2007 are calculated as follows:

	Three Months Ended December 31	
	2008	2007
	(In thousands, except per share amounts)	
Net income	$75,963	$73,803
Denominator for basic income per share — weighted average common shares	90,471	89,006
Effect of dilutive securities:		
Restricted and other shares	559	496
Stock options	36	106
Denominator for diluted income per share — weighted average common shares	91,066	89,608
Income per share — basic	$ 0.84	$ 0.83
Income per share — diluted	$ 0.83	$ 0.82

There were approximately 231,000 out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2008. There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2007 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 months ended December 31, 2008 and 2007 are presented in the following table. All 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 December 31			
	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,703	$ 3,878	$2,946	$3,341
Interest cost	7,554	6,736	3,520	2,912
Expected return on assets	(6,238)	(6,310)	(573)	(715)
Amortization of transition asset	—	—	378	378
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

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2008 and 2007 are as follows:

	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
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 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009.

We contributed $2.6 million to our other post-retirement benefit plans during the three months ended December 31, 2008. We expect to contribute a total of approximately $10 million to these plans during fiscal 2009.

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, 2008, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2008. 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 December 31, 2008, AEM was committed to purchase 77.6 Bcf within one year, 30.2 Bcf within one to three years and 1.2 Bcf after three years under indexed contracts. AEM is committed to purchase 1.6 Bcf within one year under fixed price contracts with prices ranging from $4.14 to $13.20 per Mcf. Purchases under these contracts totaled $527.5 million and $572.0 million for the three months ended December 31, 2008 and 2007.

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 its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of December 31, 2008 are as follows (in thousands):

2009	$243,310
2010	90,146
2011	8,240
2012	8,006
2013	8,102
Thereafter	2,727
	$360,531

Regulatory Matters

During the three months ended December 31, 2008, we concluded annual rate filing mechanisms we had filed in our Mid-Tex and West Texas service areas. As of December 31, 2008, rate cases were in progress in our City of Dallas and Tennessee 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 three months ended December 31, 2008, 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.

Income statements for the three-month periods ended December 31, 2008 and 2007 by segment are presented in the following tables:

	Three Months Ended December 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$1,055,772	$30,222	$616,844	$13,494	$ —	$1,716,332
Intersegment revenues	196	24,460	170,651	2,954	(198,261)	—
	1,055,968	54,682	787,495	16,448	(198,261)	1,716,332
Purchased gas cost	757,584	—	757,472	3,903	(197,839)	1,321,120
Gross profit	298,384	54,682	30,023	12,545	(422)	395,212
Operating expenses						
Operation and maintenance	97,994	27,569	8,516	1,184	(508)	134,755
Depreciation and amortization	47,139	4,955	401	631	—	53,126
Taxes, other than income	40,746	2,788	593	10	—	44,137
Total operating expenses	185,879	35,312	9,510	1,825	(508)	232,018
Operating income	112,505	19,370	20,513	10,720	86	163,194
Miscellaneous income (expense)	3,121	815	301	2,161	(6,699)	(301)
Interest charges	32,887	8,079	3,902	736	(6,613)	38,991
Income before income taxes	82,739	12,106	16,912	12,145	—	123,902
Income tax expense	32,606	4,445	6,337	4,551	—	47,939
Net income	$ 50,133	$ 7,661	$ 10,575	$ 7,594	$ —	$ 75,963
Capital expenditures	$ 89,003	$ 5,060	$ 29	$13,275	$ —	$ 107,367

	Three Months Ended December 31, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$928,029	$22,437	$702,722	$4,322	$ —	$1,657,510
Intersegment revenues	148	22,609	137,995	2,405	(163,157)	—
	928,177	45,046	840,717	6,727	(163,157)	1,657,510
Purchased gas cost	654,977	—	794,754	729	(162,588)	1,287,872
Gross profit	273,200	45,046	45,963	5,998	(569)	369,638
Operating expenses						
Operation and maintenance	97,247	15,432	7,877	1,288	(655)	121,189
Depreciation and amortization	42,832	4,916	387	378	—	48,513
Taxes, other than income	35,618	2,444	3,000	365	—	41,427
Total operating expenses	175,697	22,792	11,264	2,031	(655)	211,129
Operating income	97,503	22,254	34,699	3,967	86	158,509
Miscellaneous income (expense)	476	174	796	2,028	(3,567)	(93)
Interest charges	31,214	7,071	1,314	699	(3,481)	36,817
Income before income taxes	66,765	15,357	34,181	5,296	—	121,599
Income tax expense	26,601	5,510	13,581	2,104	—	47,796
Net income	$ 40,164	$ 9,847	$ 20,600	$3,192	$ —	$ 73,803
Capital expenditures	$ 84,313	$ 8,382	$ 31	$1,429	$ —	$ 94,155

Balance sheet information at December 31, 2008 and September 30, 2008 by segment is presented in the following tables:

	December 31, 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	$3,533,249	$584,882	$ 7,387	$ 69,230	$ —	$4,194,748
Investment in subsidiaries	466,443	—	(2,096)	—	(464,347)	—
Current assets						
Cash and cash equivalents	36,931	—	32,052	816	—	69,799
Assets from risk management activities	—	—	41,016	24,608	(25,549)	40,075
Other current assets	1,151,129	27,029	413,676	62,728	(81,328)	1,573,234
Intercompany receivables	534,996	—	—	142,753	(677,749)	—
Total current assets	1,723,056	27,029	486,744	230,905	(784,626)	1,683,108
Intangible assets	—	—	1,931	—	—	1,931
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	19	—	13,214	44	(44)	13,233
Deferred charges and other assets	166,669	6,718	853	14,641	—	188,881
	$6,459,356	$750,996	$532,315	$325,249	$(1,249,017)	$6,818,899
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,078,076	$137,805	$102,735	$225,903	$ (466,443)	$2,078,076
Long-term debt	1,719,396	—	—	524	—	1,719,920
Total capitalization	3,797,472	137,805	102,735	226,427	(466,443)	3,797,996
Current liabilities						
Current maturities of long-term debt	400,000	—	—	507	—	400,507
Short-term debt	401,683	—	—	—	(40,850)	360,833
Liabilities from risk management activities	47,448	—	30,596	937	(25,549)	53,432
Other current liabilities	863,569	8,330	291,154	78,442	(38,351)	1,203,144
Intercompany payables	—	535,064	142,685	—	(677,749)	—
Total current liabilities	1,712,700	543,394	464,435	79,886	(782,499)	2,017,916
Deferred income taxes	385,547	65,874	(35,664)	15,598	(31)	431,324
Noncurrent liabilities from risk management activities	3,885	—	122	—	(44)	3,963
Regulatory cost of removal obligation	305,784	—	—	—	—	305,784
Deferred credits and other liabilities	253,968	3,923	687	3,338	—	261,916
	$6,459,356	$750,996	$532,315	$325,249	$(1,249,017)	$6,818,899

	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

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 December 31, 2008, and the related condensed consolidated statements of income and cash flows for the three-month periods ended December 31, 2008 and 2007. 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
February 3, 2009

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", "seek", "strategy" or similar 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 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 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.

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, 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 three months ended December 31, 2008.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three months ended December 31, 2008 and 2007:

	Three Months Ended December 31	
	2008	2007
	(In thousands, except per share data)	
Operating revenues	$1,716,332	$1,657,510
Gross profit	395,212	369,638
Operating expenses	232,018	211,129
Operating income	163,194	158,509
Miscellaneous expense	(301)	(93)
Interest charges	38,991	36,817
Income before income taxes	123,902	121,599
Income tax expense	47,939	47,796
Net income	$ 75,963	$ 73,803
Diluted net income per share	$ 0.83	$ 0.82

Our consolidated net income during the three months ended December 31, 2008 and 2007 was earned in each of our business segments as follows:

	Three Months Ended December 31		
	2008	2007	Change
	(In thousands)		
Natural gas distribution segment	$50,133	$40,164	$ 9,969
Regulated transmission and storage segment	7,661	9,847	(2,186)
Natural gas marketing segment	10,575	20,600	(10,025)
Pipeline, storage and other segment	7,594	3,192	4,402
Net income	$75,963	$73,803	$ 2,160

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

	Three Months Ended December 31		
	2008	2007	Change
	(In thousands, except per share data)		
Regulated operations	$57,794	$50,011	$ 7,783
Nonregulated operations	18,169	23,792	(5,623)
Consolidated net income	$75,963	$73,803	$ 2,160
Diluted EPS from regulated operations	$ 0.63	$ 0.56	$ 0.07
Diluted EPS from nonregulated operations	0.20	0.26	(0.06)
Consolidated diluted EPS	$ 0.83	$ 0.82	$ 0.01

The following summarizes the results of our operations and other significant events for the three months ended December 31, 2008:

- Regulated operations generated 76 percent of our net income during the three months ended December 31, 2008 compared to 68 percent during the three months ended December 31, 2007. The $7.8 million increase in our regulated operations net income primarily reflects favorable ratemaking activity coupled with higher transportation and priority reservation fees, which were partially offset by an 11 percent increase in operating expenses.

- Nonregulated operations contributed 24 percent of net income during the three months ended December 31, 2008 compared to 32 percent during the three months ended December 31, 2007. The $5.6 million decrease in our nonregulated operations net income primarily reflects a decrease in unrealized margins partially offset by favorable asset optimization margins.
- For the three months ended December 31, 2008, we generated $150.7 million in operating cash flow compared with $61.4 million for the three months ended December 31, 2007, primarily reflecting the timing of accounts receivable collections and purchases of gas stored underground.
- During the first quarter of fiscal 2009, we entered into two new 364-day committed credit facilities that will provide $587.5 million to help fund our natural gas purchases and working capital needs.

Three Months Ended December 31, 2008 compared with Three Months Ended December 31, 2007

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. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

Beginning January 1, 2009, changes in our franchise fee agreements will become effective that should significantly reduce the impact of this timing difference on a prospective basis.

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.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2008 and 2007 are presented below.

	Three Months Ended December 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	$298,384	$273,200	$25,184
Operating expenses	185,879	175,697	10,182
Operating income	112,505	97,503	15,002
Miscellaneous income	3,121	476	2,645
Interest charges	32,887	31,214	1,673
Income before income taxes	82,739	66,765	15,974
Income tax expense	32,606	26,601	6,005
Net income	$ 50,133	$ 40,164	$ 9,969
Consolidated natural gas distribution sales volumes — MMcf	91,446	84,767	6,679
Consolidated natural gas distribution transportation volumes — MMcf	34,336	33,749	587
Total consolidated natural gas distribution throughput — MMcf	125,782	118,516	7,266
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.45	$ 0.44	$ 0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 8.28	$ 7.73	$ 0.55

The following table shows our operating income by natural gas distribution division for the three months ended December 31, 2008 and 2007. 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 December 31		
	2008	2007	Change
	(In thousands)		
Mid-Tex	$ 52,678	$50,225	$ 2,453
Kentucky/Mid-States	19,025	14,168	4,857
Louisiana	14,584	11,932	2,652
West Texas	8,013	4,976	3,037
Mississippi	8,435	7,829	606
Colorado-Kansas	8,601	6,688	1,913
Other	1,169	1,685	(516)
Total	$112,505	$97,503	$15,002

The $25.2 million increase in natural gas distribution gross profit primarily reflects a $15.3 million increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division, which increased $11.3 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). The current year period also reflects $4.0 million in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. In addition, the increase in gross profit reflects a six percent increase in distribution throughput. Finally, gross profit increased $8.1 million compared with the prior-year quarter due 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.

Partially offsetting these increases was a decrease of approximately $0.3 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This decrease, combined with an $8.1 million quarter-over-quarter increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in an $8.4 million decrease 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 and taxes, other than income, increased $10.2 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $2.2 million, primarily due to a $2.1 million noncash charge to impair certain available-for-sale investments due to the recent deterioration of the financial markets.

Depreciation and amortization expense increased $4.3 million for the first quarter of fiscal 2009 compared with first 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 $1.7 million due to higher average short-term debt balances, interest rates and commitment fees experienced during the current-year quarter compared to the prior-year quarter. These increases are associated with the recent adverse conditions in the credit markets.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the three months ended December 31, 2008 are discussed below. The amounts described below represent the gross revenues that were requested or received in each rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Annual Rate Filing Mechanisms

In April 2008, the Mid-Tex Division filed its first RRM with the Settled Cities. The filing requested an increase in rates of $33.3 million on a system-wide basis, of which $26.7 million applied to the Settled Cities. We reached an agreement with representatives of the Settled Cities to increase rates $20.0 million on a system-wide basis, which were implemented beginning in November 2008. The impact to the Mid-Tex Division for the Settled Cities is approximately $16.0 million.

In the West Texas Division, the Company reached an agreement with representatives of the West Texas Cities with respect to its RRM filing to increase rates a total of $3.9 million. The $3.9 million will be collected through the true-up portion of the RRM tariff rates over a 9½ month period beginning in November 2008.

In May 2008, the City of Lubbock approved its Conservation and Customer Value Plan (CCVP), which contained an annual rate review mechanism that would adjust rates to reflect changes in the West Texas Division's cost of service and rate base. The West Texas Division filed its annual review filing under the CCVP in June 2008. The Company and city officials were unable to reach a mutually agreeable settlement, and in December 2008, the City Council passed an ordinance withdrawing the CCVP tariff. The Company is currently evaluating it options.

In December 2008, we filed our TransLa annual rate stabilization clause with the Louisiana Public Service Commission requesting an increase of $0.9 million. The filing was for the test year ended September 30, 2008. We anticipate final resolution of this proceeding by March 2009.

In September 2008, we filed our Mississippi stable rate filing with the Mississippi Public Service Commission (MPSC) requesting an increase 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 is only applicable to the City of Dallas and the Mid-Tex environs and seeks a $1.8 million increase for customers in those service areas only. Rates were approved for this filing in December 2008 and will be implemented in February 2009.

Rate Case Filings

In October 2008, our Kentucky/Mid-States Division filed a rate case with the Tennessee Regulatory Authority seeking a rate increase of $6.3 million. The filing includes a rate base of approximately $191.0 million, a 50/50 capital structure and requests an authorized return on equity of 11.7 percent. We are currently working through discovery on the case. In January 2009, the Consumer Advocate and Protection Division recommended a decrease in rates of $3.7 million. Any adjustment to rates is expected to be implemented no later than April 2009.

In November 2008, the Mid-Tex Division filed a statement of intent to increase rates for customers within the City of Dallas by $9.1 million. The City of Dallas suspended the filing on December 10, 2008 and is expected to take final action on the filing by the end of February 2009.

Other Ratemaking Activity

In May 2007, our Mid-Tex Division filed for a 36-month gas contract review filing. This filing is mandated by prior Railroad Commission of Texas (RRC) orders and relates 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. The RRC is expected to render it decision in February 2009.

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.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2008 and 2007 are presented below.

	Three Months Ended December 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 24,352	$ 22,388	$ 1,964
Third-party transportation	25,366	18,232	7,134
Storage and park and lend services	2,357	2,039	318
Other	2,607	2,387	220
Gross profit	54,682	45,046	9,636
Operating expenses	35,312	22,792	12,520
Operating income	19,370	22,254	(2,884)
Miscellaneous income	815	174	641
Interest charges	8,079	7,071	1,008
Income before income taxes	12,106	15,357	(3,251)
Income tax expense	4,445	5,510	(1,065)
Net income	$ 7,661	$ 9,847	$ (2,186)
Gross pipeline transportation volumes — MMcf	192,172	188,864	3,308
Consolidated pipeline transportation volumes — MMcf	135,858	136,200	(342)

The $9.6 million increase in gross profit primarily was attributable to a $3.7 million increase resulting from higher transportation fees on through-system deliveries due to market conditions and a $3.3 million increase from higher priority reservation fees. The improvement in gross profit also reflects a $1.4 million increase due to our 2006 and 2007 GRIP filings. Throughput was flat as increased city-gate, electrical generation and HUB deliveries offset decreased Barnett Shale receipts and industrial deliveries.

Operating expenses increased $12.5 million primarily due to increased employee and pipeline maintenance costs.

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 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 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 December 31, 2008 and 2007 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 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 December 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 18,553	$ 18,173	$ 380
Asset optimization	36,939	(525)	37,464
	55,492	17,648	37,844
Unrealized margins	(25,469)	28,315	(53,784)
Gross profit	30,023	45,963	(15,940)
Operating expenses	9,510	11,264	(1,754)
Operating income	20,513	34,699	(14,186)
Miscellaneous income	301	796	(495)
Interest charges	3,902	1,314	2,588
Income before income taxes	16,912	34,181	(17,269)
Income tax expense	6,337	13,581	(7,244)
Net income	$ 10,575	$ 20,600	$(10,025)
Gross natural gas marketing sales volumes — MMcf	110,658	108,709	1,949
Consolidated natural gas marketing sales volumes — MMcf	93,308	96,206	(2,898)
Net physical position (Bcf)	16.3	17.7	(1.4)

The $15.9 million decrease in our natural gas marketing segment's gross profit primarily was driven by a $53.8 million decrease in unrealized margins. This decrease primarily reflects the recognition of previously unrecognized margins in realized margins, as a result of cycling more gas from storage and settlement of the corresponding financial instruments. This decrease was partially offset by a smaller widening during the current quarter compared with the prior-year quarter of the spreads between current cash prices and forward natural gas prices as cash prices have declined more rapidly than prices for the forward delivery months.

The decrease in unrealized margins was partially offset by a $37.5 million increase in asset optimization margins. In the prior year, as a result of a less volatile natural gas market, AEM elected to defer storage withdrawals and reset the corresponding financial instruments to increase the potential gross profit it could realize in future periods from its asset optimization activities. During the quarter, AEM realized substantially all of the gains it had captured as a result of deferring storage in prior periods as the storage was withdrawn and the corresponding financial instruments were settled.

In addition, the decrease in gross profit generated from unrealized margins was also partially offset by a $0.4 million increase in realized delivered gas margins. The increase was largely attributable to higher gross sales volumes combined with slightly higher per-unit margins, compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, decreased $1.8 million primarily due to the absence in the current year of $2.4 million related to tax matters incurred in the prior-year quarter partially offset by an increase in employee 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 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 December 31, 2008 and September 30, 2008.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gain	Potential Gross Profit[1]
	(Bcf)	(In millions)	(In millions)	(In millions)
December 31, 2008	16.3	$20.7	$ 4.8	$15.9
September 30, 2008	8.0	$48.5	$36.4	$12.1

(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 December 31, 2008, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $20.7 million. This amount will be reduced by $4.8 million of net unrealized gains recorded in the financial statements as of December 31, 2008 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit was $15.9 million at December 31, 2008.

The $3.8 million increase in potential gross profit as compared to September 30, 2008, is comprised of a $31.6 million decrease in unrealized gains and an unfavorable movement in the market prices used to value our natural gas storage inventory, partially offset by a $27.8 million decrease in the economic gross profit, principally due to the withdrawal of physical inventory and the realization of financial instruments settled during the period. During this process, AEM increased its net physical position 8.3 Bcf; however, the captured spreads were lower than in prior periods.

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 December 31, 2008 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 December 31, 2008, without encountering operational or other issues, we anticipate that approximately half of the potential gross profit as of December 31, 2008 will be recognized during the second quarter of fiscal 2009.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS) and Atmos Power Systems, Inc., which are each wholly owned by Atmos Energy Holdings, Inc.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of December 31, 2008, these activities did not represent a significant portion of this segment's operations.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Results for this segment are primarily impacted 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 December 31, 2008 and 2007 are presented below.

	Three Months Ended December 31		
	2008	2007	Change
	(In thousands)		
Storage and transportation services	$ 2,988	$2,981	$ 7
Asset optimization	4,340	(231)	4,571
Other	2,443	875	1,568
Unrealized margins	2,774	2,373	401
Gross profit	12,545	5,998	6,547
Operating expenses	1,825	2,031	(206)
Operating income	10,720	3,967	6,753
Miscellaneous income	2,161	2,028	133
Interest charges	736	699	37
Income before income taxes	12,145	5,296	6,849
Income tax expense	4,551	2,104	2,447
Net income	$ 7,594	$3,192	$4,402

Gross profit from our pipeline, storage and other segment increased $6.5 million primarily due to a $4.6 million increase in asset optimization margins as a result of strong transportation margins earned on excess pipeline capacity under certain asset management agreements in the current-year period coupled with a sale of inventory in the quarter.

Operating expenses for the three months ended December 31, 2008 were consistent with the prior-year quarter.

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 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. At December 31, 2008, the total amount used under this facility was $360.8 million and $205.9 million was available. However, subsequent to quarter end, credit market conditions have improved, both as to availability and interest rates, and we have been able to obtain sufficient levels of commercial paper to substantially reduce direct borrowings on this facility.

During the first quarter of fiscal 2009, we strengthened the sources of our liquidity with the execution of two new committed credit facilities. 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. 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. As a result of executing these new agreements, we have a total of $1.2 billion available to us under four committed credit facilities. As of December 31, 2008, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $614 million.

Our $18 million unsecured committed credit facility expires in March 2009. We are working to renew this credit facility and we believe these renewal efforts will be successful. Additionally, our $400 million 4.00% unsecured senior notes will mature in October 2009. We are currently evaluating alternatives to finance this debt, and we believe we will be able to successfully refinance these notes.

We believe the liquidity provided by our 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 three months ended December 31, 2008, we generated operating cash flow of $150.7 million from operating activities compared with $61.4 million for the three months ended December 31, 2007. Period over period, the $89.3 million increase primarily was attributable to favorable changes in accounts receivable and gas stored underground, which increased operating cash flow by $83.9 million. These changes reflect improved timing of accounts receivable collections and purchases of natural gas to fill our storage facilities.

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, 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 three months ended December 31, 2008, capital expenditures were $107.4 million compared with $94.2 million for the three months ended December 31, 2007. The increase in capital spending primarily reflects spending for nonregulated growth projects and increased levels of regulatory compliance-related spending in the Mid-Tex Division.

Cash flows from financing activities

For the three months ended December 31, 2008, our financing activities reflected a use of cash of $19.1 million. For the three months ended December 31, 2007, financing activities provided $25.7 million. Our significant financing activities for the three months ended December 31, 2008 and 2007 are summarized as follows:

- During the three months ended December 31, 2008, we increased our borrowings by a net $5.3 million under our short-term credit facilities compared with $50.7 million in the prior-year quarter. The reduction in the net borrowings reflects the timing of the use of our line of credit to finance natural gas purchases and working capital.
- We repaid $0.3 million of long-term debt during the three months ended December 31, 2008 compared with $1.7 million during the three months ended December 31, 2007. Payments in both periods reflected regularly scheduled payments in accordance with our various debt agreements.
- During the three months ended December 31, 2008, we paid $30.2 million in cash dividends compared with $29.2 million for the three months ended December 31, 2007. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.325 per share during the three months ended December 31, 2007 to $0.33 per share during the three months ended December 31, 2008 combined with new share issuances under our various equity plans.
- During the three months ended December 31, 2008, we issued 0.3 million shares of common stock under our various equity plans, which generated net proceeds of $6.1 million. In addition, we granted 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the three months ended December 31, 2008 and 2007.

	Three Months Ended December 31	
	2008	**2007**
Shares issued:		
Direct Stock Purchase Plan	108,582	95,891
Retirement Savings Plan and Trust	155,195	140,071
1998 Long-Term Incentive Plan	520,124	343,673
Outside Directors Stock-for-Fee Plan	911	817
Total shares issued	784,812	580,452

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 $600 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide $1.2 billion of working capital funding. As of December 31, 2008, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $614 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities. As of December 31, 2008, we had approximately $450 million available for issuance under the registration statement. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $200 million of equity securities and $250 million of senior debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

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 credit rating from BBB to BBB+ and affirmed a stable outlook. S&P cited improved financial performance and rate case decisions that have increased cash flow as the key drivers for the upgrade. Additionally, in January 2009, Moody's changed our rating outlook from stable to positive. 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+	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

None of our ratings are currently under review. However, a significant degradation in our operating performance, 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 or our inability to refinance on a timely basis our $400 million 4.00% unsecured senior notes maturing in October 2009 could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean even 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 December 31, 2008. 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 as of December 31, 2008, September 30, 2008 and December 31, 2007:

	December 31, 2008		September 30, 2008		December 31, 2007	
	(In thousands, except percentages)					
Short-term debt	$ 360,833	7.9%	$ 350,542	7.7%	$ 202,244	4.6%
Long-term debt	2,120,427	46.5%	2,120,577	46.9%	2,128,533	48.8%
Shareholders' equity	2,078,076	45.6%	2,052,492	45.4%	2,032,483	46.6%
Total capitalization	$4,559,336	100.0%	$4,523,611	100.0%	$4,363,260	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 54.4 percent at December 31, 2008, 54.6 percent at September 30, 2008 and 53.4 percent at December 31, 2007. 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 three months ended December 31, 2008.

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. We have drilled a test well and are currently evaluating the results. Additionally, we have submitted a pre-filing request with the Federal Energy Regulatory Commission (FERC) to construct and operate the project. We expect approval of this request in the third quarter of fiscal 2009. Finally, we have engaged the services of an investment bank to assist us in determining the optimal ownership and/or development alternatives with respect to this project.

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 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 months ended December 31, 2008 and 2007:

	Three Months Ended December 31	
	2008	2007
	(In thousands)	
Fair value of contracts at beginning of period	$(63,677)	$(21,053)
Contracts realized/settled	(53,766)	(22,338)
Fair value of new contracts	(3,223)	(1,681)
Other changes in value	69,352	23,544
Fair value of contracts at end of period	$(51,314)	$(21,528)

The fair value of our natural gas distribution segment's financial instruments at December 31, 2008 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2008				
	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	$(47,448)	$(3,866)	$—	$—	$(51,314)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(47,448)	$(3,866)	$—	$—	$(51,314)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three months ended December 31, 2008 and 2007:

	Three Months Ended December 31	
	2008	2007
	(In thousands)	
Fair value of contracts at beginning of period	$ 16,542	$ 26,808
Contracts realized/settled	(20,247)	5,075
Fair value of new contracts	—	—
Other changes in value	(24,893)	19,976
Fair value of contracts at end of period	(28,598)	51,859
Netting of cash collateral	75,825	(30,189)
Cash collateral and fair value of contracts at period end	$ 47,227	$ 21,670

The fair value of our natural gas marketing segment's financial instruments at December 31, 2008 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2008				
	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	$(41,734)	$13,136	$—	$—	$(28,598)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(41,734)	$13,136	$—	$—	$(28,598)

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. Accordingly, our fiscal 2009 pension and postretirement medical costs were materially the same as in fiscal 2008.

For the three months ended December 31, 2008 and 2007, our total net periodic pension and other benefits cost was $12.1 million and $12.0 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 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009. The need for this funding reflects 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 will increase 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 $10 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.

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-month periods ended December 31, 2008 and 2007.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended December 31	
	2008	2007
METERS IN SERVICE, end of period		
Residential	2,929,319	2,925,426
Commercial	273,590	275,438
Industrial	2,232	2,319
Public authority and other	9,236	19,147
Total meters	3,214,377	3,222,330
INVENTORY STORAGE BALANCE — Bcf	58.2	60.0
SALES VOLUMES — MMcf[1]		
Gas sales volumes		
Residential	54,208	49,031
Commercial	28,329	26,620
Industrial	5,400	5,954
Public authority and other	3,509	3,162
Total gas sales volumes	91,446	84,767
Transportation volumes	35,285	34,853
Total throughput	126,731	119,620
OPERATING REVENUES (000's)[1]		
Gas sales revenues		
Residential	$ 647,100	$ 554,289
Commercial	302,694	268,469
Industrial	50,155	51,176
Public authority and other	31,394	30,604
Total gas sales revenues	1,031,343	904,538
Transportation revenues	15,766	15,005
Other gas revenues	8,859	8,634
Total operating revenues	$1,055,968	$ 928,177
Average transportation revenue per Mcf	$ 0.45	$ 0.43
Average cost of gas per Mcf sold	$ 8.28	$ 7.73

See footnotes following these tables.

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

	Three Months Ended December 31	
	2008	2007
CUSTOMERS, end of period		
Industrial	703	735
Municipal	59	61
Other	490	469
Total	1,252	1,265
INVENTORY STORAGE BALANCE — Bcf		
Natural gas marketing	15.8	22.3
Pipeline, storage and other	2.5	2.6
Total	18.3	24.9
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(1)	192,172	188,864
NATURAL GAS MARKETING SALES VOLUMES — MMcf(1)	110,658	108,709
OPERATING REVENUES (000's)(1)		
Regulated transmission and storage	$ 54,682	$ 45,046
Natural gas marketing	787,495	840,717
Pipeline, storage and other	16,448	6,727
Total operating revenues	$858,625	$892,490

Notes 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 year ended September 30, 2008. During the three months ended December 31, 2008, 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 December 31, 2008 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first 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 three months ended December 31, 2008, 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 environmental-related 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 environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: February 4, 2009

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number
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.

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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2008

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of July 31, 2008.

Class	Shares Outstanding
No Par Value	90,627,522

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KCC	Kansas Corporation Commission
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2008	September 30, 2007
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,604,416	$5,396,070
Less accumulated depreciation and amortization	1,591,528	1,559,234
Net property, plant and equipment	4,012,888	3,836,836
Current assets		
Cash and cash equivalents	46,501	60,725
Cash held on deposit in margin account	62,152	—
Accounts receivable, net	601,164	380,133
Gas stored underground	571,532	515,128
Other current assets	115,609	112,909
Total current assets	1,396,958	1,068,895
Goodwill and intangible assets	737,221	737,692
Deferred charges and other assets	237,723	253,494
	$6,384,790	$5,896,917
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, 2008 — 90,571,457 shares; September 30, 2007 — 89,326,537 shares	$ 453	$ 447
Additional paid-in capital	1,732,775	1,700,378
Retained earnings	371,486	281,127
Accumulated other comprehensive income (loss)	693	(16,198)
Shareholders' equity	2,105,407	1,965,754
Long-term debt	2,119,729	2,126,315
Total capitalization	4,225,136	4,092,069
Current liabilities		
Accounts payable and accrued liabilities	582,353	355,255
Other current liabilities	472,088	409,993
Short-term debt	113,257	150,599
Current maturities of long-term debt	1,059	3,831
Total current liabilities	1,168,757	919,678
Deferred income taxes	450,669	370,569
Regulatory cost of removal obligation	280,108	271,059
Deferred credits and other liabilities	260,120	243,542
	$6,384,790	$5,896,917

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2008	2007
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 676,639	$ 548,251
Regulated transmission and storage segment	46,286	36,707
Natural gas marketing segment	1,189,722	854,167
Pipeline, storage and other segment	3,880	2,073
Intersegment eliminations	(277,382)	(223,046)
	1,639,145	1,218,152
Purchased gas cost		
Natural gas distribution segment	476,711	357,608
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,192,353	854,743
Pipeline, storage and other segment	706	228
Intersegment eliminations	(276,847)	(222,443)
	1,392,923	990,136
Gross profit	246,222	228,016
Operating expenses		
Operation and maintenance	117,822	115,141
Depreciation and amortization	50,356	48,974
Taxes, other than income	57,335	52,881
Impairment of long-lived assets	—	3,289
Total operating expenses	225,513	220,285
Operating income	20,709	7,731
Miscellaneous income	1,600	4,266
Interest charges	33,470	34,479
Loss before income taxes	(11,161)	(22,482)
Income tax benefit	(4,573)	(9,122)
Net loss	$ (6,588)	$ (13,360)
Basic net loss per share	$ (0.07)	$ (0.15)
Diluted net loss per share	$ (0.07)	$ (0.15)
Cash dividends per share	$ 0.325	$ 0.320
Weighted average shares outstanding:		
Basic	89,648	88,366
Diluted	89,648	88,366

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2008	2007
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$3,126,672	$2,973,528
Regulated transmission and storage segment	142,772	122,647
Natural gas marketing segment	3,159,092	2,360,902
Pipeline, storage and other segment	20,629	27,483
Intersegment eliminations	(668,525)	(588,193)
	5,780,640	4,896,367
Purchased gas cost		
Natural gas distribution segment	2,296,020	2,174,071
Regulated transmission and storage segment	—	—
Natural gas marketing segment	3,099,428	2,275,291
Pipeline, storage and other segment	1,773	682
Intersegment eliminations	(666,835)	(585,971)
	4,730,386	3,864,073
Gross profit	1,050,254	1,032,294
Operating expenses		
Operation and maintenance	359,064	342,373
Depreciation and amortization	147,659	149,035
Taxes, other than income	153,170	149,694
Impairment of long-lived assets	—	3,289
Total operating expenses	659,893	644,391
Operating income	390,361	387,903
Miscellaneous income	2,974	7,683
Interest charges	103,803	109,273
Income before income taxes	289,532	286,313
Income tax expense	110,783	111,907
Net income	$ 178,749	$ 174,406
Basic net income per share	$ 2.00	$ 2.02
Diluted net income per share	$ 1.99	$ 2.00
Cash dividends per share	$ 0.975	$ 0.960
Weighted average shares outstanding:		
Basic	89,281	86,378
Diluted	89,937	87,011

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2008	2007
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 178,749	$ 174,406
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	147,659	149,035
Charged to other accounts	106	148
Deferred income taxes	77,864	37,266
Other	12,767	17,959
Net assets / liabilities from risk management activities	35,169	12,325
Net change in operating assets and liabilities	(34,933)	161,531
Net cash provided by operating activities	417,381	552,670
Cash Flows From Investing Activities		
Capital expenditures	(312,878)	(263,023)
Other, net	(4,303)	(9,867)
Net cash used in investing activities	(317,181)	(272,890)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(35,721)	(382,416)
Net proceeds from long-term debt offering	—	247,461
Settlement of Treasury lock agreement	—	4,750
Repayment of long-term debt	(9,945)	(2,685)
Cash dividends paid	(87,821)	(83,118)
Issuance of common stock	19,063	18,883
Net proceeds from equity offering	—	191,913
Net cash used in financing activities	(114,424)	(5,212)
Net increase (decrease) in cash and cash equivalents	(14,224)	274,568
Cash and cash equivalents at beginning of period	60,725	75,815
Cash and cash equivalents at end of period	$ 46,501	$ 350,383

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2008

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 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 managed by 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 southeastern and midwestern states 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 derivative instruments.

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., each of which are wholly-owned by AEH. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, APS manages our natural gas gathering operations, which were limited in nature as of June 30, 2008. AES provides limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

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 its Annual Report on Form 10-K for the fiscal year ended September 30, 2007. Because of seasonal and other factors, the results of operations for the three and nine-month periods ended June 30, 2008 are not indicative of our results of operations for the full 2008 fiscal year, which ends September 30, 2008.

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 year ended September 30, 2007. Except for the Company's adoption of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48), discussed below, there were no significant changes to those accounting policies during the nine months ended June 30, 2008.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN 48 on October 1, 2007. As a result of adopting FIN 48, we determined that we had $6.1 million of liabilities associated with uncertain tax positions. Of this amount, $0.5 million was recognized as a result of adopting FIN 48 with an offsetting reduction to retained earnings.

Prior to October 1, 2007, the $5.6 million liability previously recorded for uncertain tax positions was reflected on the consolidated balance sheet as a component of deferred income taxes. As a result of adopting FIN 48, we recorded a $3.7 million liability as a component of other current liabilities and $2.4 million as a component of deferred credits and other liabilities, with offsetting decreases to the deferred income tax liability.

As of June 30, 2008, we had recorded liabilities associated with uncertain tax positions totaling $8.0 million. The realization of all of these tax benefits would reduce our income tax expense by approximately $8.0 million.

The following table presents the changes in unrecognized tax benefits for the nine months ended June 30, 2008 (in thousands):

Total unrecognized tax benefits at October 1, 2007	$6,156
Gross increases for current year's tax positions	—
Gross increases for prior years' tax positions	2,331
Gross decreases for prior years' tax positions	(528)
Settlements	—
Total unrecognized tax benefits at June 30, 2008	$7,959

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We did not recognize any material penalty and interest expenses during the nine months ended June 30, 2008.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2001. The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns, and we anticipate these examinations will be completed by the end of fiscal 2008. We believe all material tax items which relate to the years under audit have been properly accrued.

Additionally, during the second quarter of fiscal 2008, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (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, 2008 and September 30, 2007 included the following:

	June 30, 2008	September 30, 2007
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 52,623	$ 59,022
Merger and integration costs, net	7,689	7,996
Deferred gas costs	21,473	14,797
Environmental costs	1,014	1,303
Rate case costs	13,758	10,989
Deferred franchise fees	690	796
Other	8,474	10,719
	$105,721	$105,622
Regulatory liabilities:		
Deferred gas costs	$109,439	$ 84,043
Regulatory cost of removal obligation	300,994	295,241
Deferred income taxes, net	165	165
Other	7,292	7,503
	$417,890	$386,952

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.

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, 2008 and 2007:

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
	(In thousands)			
Net income (loss)	$(6,588)	$(13,360)	$178,749	$174,406
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $531 and $215 for the three months ended June 30, 2008 and 2007 and of $(140) and $964 for the nine months ended June 30, 2008 and 2007	866	353	(231)	1,575
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $482 and $1,863 for the three months ended June 30, 2008 and 2007 and $1,446 and $3,373 for the nine months ended June 30, 2008 and 2007	787	3,039	2,361	5,501
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $1,850 and $(2,832) for the three months ended June 30, 2008 and 2007 and $9,047 and $12,504 for the nine months ended June 30, 2008 and 2007	3,018	(4,621)	14,761	20,401
Comprehensive income (loss)	$(1,917)	$(14,589)	$195,640	$201,883

Accumulated other comprehensive income (loss), net of tax, as of June 30, 2008 and September 30, 2007 consisted of the following unrealized gains (losses):

	June 30, 2008	September 30, 2007
	(In thousands)	
Accumulated other comprehensive income (loss):		
Unrealized holding gains on investments	$ 2,576	$ 2,807
Treasury lock agreements	(11,891)	(14,252)
Cash flow hedges	10,008	(4,753)
	$ 693	$(16,198)

Recently issued accounting pronouncements

In March 2008, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133.* SFAS 161 expands the disclosure requirements for derivative instruments and for hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. The provisions of this standard will be effective for us beginning January 1, 2009. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued FASB Statement No. 141 (revised 2007), *Business Combinations.* SFAS 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS 141(R) significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under SFAS 141(R), changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. The provisions of this standard will apply to any acquisitions we may complete after October 1, 2009.

In December 2007, the FASB issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statement, an amendment of ARB No. 51.* SFAS 160 changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. The provisions of the standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at June 30, 2008 and September 30, 2007:

	Natural Gas Distribution	Natural Gas Marketing	Total
		(In thousands)	
June 30, 2008:			
Assets from risk management activities, current	$ 37,366	$ 5,534	$ 42,900
Assets from risk management activities, noncurrent	—	5,904	5,904
Liabilities from risk management activities, current	—	(50,686)	(50,686)
Liabilities from risk management activities, noncurrent	—	(3,724)	(3,724)
Net assets (liabilities)	$ 37,366	$(42,972)	$ (5,606)
September 30, 2007:			
Assets from risk management activities, current	$ —	$ 21,849	$ 21,849
Assets from risk management activities, noncurrent	—	5,535	5,535
Liabilities from risk management activities, current	(21,053)	(286)	(21,339)
Liabilities from risk management activities, noncurrent	—	(290)	(290)
Net assets (liabilities)	$(21,053)	$ 26,808	$ 5,755

Natural Gas Distribution Derivative Activities

In our natural gas distribution segment, we use a combination of physical storage and financial derivatives to partially insulate our natural gas distribution customers against gas price volatility during the winter heating season. These financial derivatives have not been designated as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Accordingly, they are recorded at fair value. However, because the costs associated with and the gains and losses arising from these financial derivatives are included in our purchased gas adjustment mechanisms, changes in the fair value of these financial derivatives are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas costs when the related costs are recovered through our rates 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 derivatives.

Natural Gas Marketing Derivative Activities

Our natural gas marketing risk management activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, and we manage our exposure to the risk of natural gas price changes through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. AEM uses financial derivatives designated as fair value hedges to offset changes in the fair value of its natural gas inventory and derivatives designated as cash flow hedges to offset anticipated purchases and sales of gas in the future. AEM also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

Pipeline, Storage and Other Derivative Activities

Our pipeline, storage and other activities are also exposed to risks associated with changes in the market price of natural gas, which are managed through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Atmos Pipeline and Storage, LLC uses financial derivatives designated as fair value hedges to offset changes in the fair value of its natural gas inventory.

Under our risk management policies for our nonregulated operations, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no net 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. We may 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, 2008, AEH had a net open position (including existing storage) of 0.1 Bcf.

Treasury Derivative Activities

We periodically manage our exposure to interest rate changes by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. Since fiscal 2004, we have executed five Treasury lock agreements.

The most recent treasury lock agreement was executed in March 2007, which fixed the Treasury yield component of the interest cost associated with $100 million of our $250 million 6.35% Senior Notes that were issued in June 2007. This Treasury lock agreement was settled in June 2007, and resulted in the receipt of $4.8 million from the counterparties.

The settlement of the five Treasury lock agreements resulted in a net $39.0 million payment to the counterparties. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income. The net realized loss recognized upon settlement of the Treasury lock agreements was initially recorded as a component of accumulated other comprehensive income and is currently being recognized as a component of interest expense over the life of the related financing arrangements.

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, 2008 and 2007:

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ —	$ 2,204	$ —	$ 2,945
Forward commodity contracts	6,636	(4,750)	16,285	(6,975)
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	787	835	2,361	2,556
Forward commodity contracts	(3,618)	129	(1,524)	27,376
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ 3,805	$(1,582)	$17,122	$25,902

(1) Utilizing an income tax rate of approximately 38 percent comprised of the effective rates in each taxing jurisdiction.

Hedge Ineffectiveness

Unrealized margins recorded in our natural gas marketing and pipeline, storage and other segments are comprised of various components, including, but not limited to, unrealized gains and losses arising from hedge ineffectiveness. Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative instrument and the hedged item and could materially affect our results of operations for the reported period. Although these unrealized gains and losses are currently recorded in our income statement, they are not indicative of the economic gross profit we anticipate realizing when the underlying physical and financial transactions are settled.

Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity are referred to as timing ineffectiveness. The portion of our unrealized margins related to basis and timing ineffectiveness gains and losses for the three and nine months ended June 30, 2008 and 2007 are as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
	(In thousands)			
Basis ineffectiveness:				
Fair value basis ineffectiveness	$(2,402)	$ 1,073	$(1,185)	$ 942
Cash flow basis ineffectiveness	(406)	1,479	(281)	710
Total basis ineffectiveness	(2,808)	2,552	(1,466)	1,652
Timing ineffectiveness:				
Fair value timing ineffectiveness	(1,842)	(1,759)	42,040	80,456
Total hedge ineffectiveness	$(4,650)	$ 793	$40,574	$82,108

4. Debt

Long-term debt

Long-term debt at June 30, 2008 and September 30, 2007 consisted of the following:

	June 30, 2008	September 30, 2007
	(In thousands)	
Unsecured 4.00% Senior Notes, due October 2009	$ 400,000	$ 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 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 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
First Mortgage Bonds		
Series P, 10.43% due May 2008	—	7,500
Other term notes due in installments through 2013	1,648	3,890
Total long-term debt	2,123,951	2,133,693
Less:		
Original issue discount on unsecured senior notes and debentures	(3,163)	(3,547)
Current maturities	(1,059)	(3,831)
	$2,119,729	$2,126,315

Short-term debt

At June 30, 2008, there was $113.3 million outstanding under our commercial paper program and bank credit facilities. At September 30, 2007, there was $150.6 million outstanding under our commercial paper program and bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of June 30, 2008, we had approximately $450 million of availability remaining under the registration statement. Due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until we received an investment grade rating from all of the three credit rating agencies.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of June 30, 2008, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility, expiring December 2011, for $600 million that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At June 30, 2008, there was $113.3 million outstanding under our commercial paper program.

The second facility is a $300 million unsecured 364-day facility expiring November 2008, that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At June 30, 2008, there were no borrowings under this facility.

The third facility is an $18 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility expired on March 31, 2008 and was renewed effective April 1, 2008 for one year with no material changes to the terms and pricing. At June 30, 2008, there were no borrowings under this facility.

The availability of funds under our 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 our revolving credit 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, 2008, our total-debt-to-total-capitalization ratio, as defined, was 55 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt-to-total-capitalization ratio.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility. On March 31, 2008, AEM and the participating banks amended the facility, primarily to extend it to March 31, 2009. In addition, the amendment removed the financial covenant relating to the amount of cumulative losses that could be incurred by AEM and its subsidiaries over a specific period of time and included provisions permitting the participating banks, or their affiliates, to participate in physical commodity transactions with AEM.

Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR for the applicable interest period plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility not to exceed a maximum ratio of total liabilities to tangible net worth of 5 to 1. At June 30, 2008, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.97 to 1. Additionally, AEM must maintain minimum levels of net working capital ranging from $20 million to $120 million and a minimum tangible net worth ranging from $21 million to $121 million. As defined in the financial covenants, at June 30, 2008, AEM's net working capital was $253.3 million and its tangible net worth was $256.5 million.

At June 30, 2008, there were no borrowings outstanding under this credit facility. However, at June 30, 2008, AEM letters of credit totaling $161.9 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 $88.1 million at June 30, 2008. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also had an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. In January 2008, the unused portion of this facility was terminated by the lending bank and the remaining balance will be terminated as the outstanding letters of credit expire. At June 30, 2008, there was $5.3 million in letters of credit outstanding under this facility.

The Company has a $200 million intercompany uncommitted revolving credit facility with AEH. This facility bears interest at the lesser of (i) the one-month LIBOR rate plus 0.20 percent or (ii) the marginal borrowing rate available to the Company on any such date under its commercial paper program. Applicable state regulatory commissions have approved this facility through December 31, 2008. At June 30, 2008, there were no borrowings outstanding under this facility.

AEH has a $200 million intercompany uncommitted demand credit facility with the Company, which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.75 percent. Applicable state regulatory commissions have approved this facility through December 31, 2008. At June 30, 2008, there was $17.3 million outstanding under this facility.

In addition, to supplement its $580 million credit facility, AEM has a $200 million intercompany uncommitted demand credit facility with AEH, which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility. At June 30, 2008, there was $41.0 million outstanding under this facility.

Debt Covenants

We had other covenants in addition to those described above. Our Series P First Mortgage Bonds contained provisions that allowed us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provided for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. In May 2008, we redeemed our Series P First Mortgage Bonds which were scheduled to mature in November 2013. Since the bonds have been redeemed, the debt covenants described above no longer apply.

We were in compliance with all of our debt covenants as of June 30, 2008. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. 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. In addition, 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. Additionally, this 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.

Except as described above, we have no 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.

5. Shareholders' Equity

Public Offering

On December 13, 2006, we completed a public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

Shareholder Rights Plan

In November 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998, the description and terms of which were set forth in a rights agreement between us and the rights agent dated May 10, 1998. From that time until the expiration of the rights agreement on May 10, 2008, when all rights terminated, each share of common stock we issued included a right that entitled the holder to purchase from us a one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment.

6. Earnings Per Share

Basic and diluted earnings (loss) per share for the three and nine months ended June 30, 2008 and 2007 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
	(In thousands, except per share amounts)			
Net income (loss)	$(6,588)	$(13,360)	$178,749	$174,406
Denominator for basic income per share — weighted average common shares	89,648	88,366	89,281	86,378
Effect of dilutive securities:				
Restricted and other shares	—	—	557	464
Stock options	—	—	99	169
Denominator for diluted income per share — weighted average common shares	89,648	88,366	89,937	87,011
Income (loss) per share — basic	$ (0.07)	$ (0.15)	$ 2.00	$ 2.02
Income (loss) per share — diluted	$ (0.07)	$ (0.15)	$ 1.99	$ 2.00

There were approximately 557,000 and 466,000 restricted and other shares and approximately 99,000 and 165,000 stock options that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2008 and 2007 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2008 and 2007 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, 2008 and 2007 are presented in the following table. All 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	
	2008	2007	2008	2007
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,879	$ 4,017	$3,342	$2,807
Interest cost	6,736	6,496	2,912	2,640
Expected return on assets	(6,311)	(6,089)	(715)	(597)
Amortization of transition asset	—	—	377	377
Amortization of prior service cost	(171)	44	—	9
Amortization of actuarial loss	1,926	2,435	—	—
Net periodic pension cost	$ 6,059	$ 6,903	$5,916	$5,236

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 11,635	$ 12,053	$10,024	$ 8,421
Interest cost	20,208	19,486	8,736	7,921
Expected return on assets	(18,932)	(18,267)	(2,145)	(1,791)
Amortization of transition asset	—	—	1,133	1,133
Amortization of prior service cost	(513)	134	—	25
Amortization of actuarial loss	5,778	7,303	—	—
Net periodic pension cost	$ 18,176	$ 20,709	$17,748	$15,709

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2008 and 2007 are as follows:

	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
Discount rate	6.30%	6.30%	6.30%	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%	5.20%

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. We are not required to contribute to our pension plans during fiscal 2008 and do not anticipate making contributions. However, we contributed $6.7 million to our other post-retirement benefit plans during the nine months ended June 30, 2008. We expect to contribute a total of approximately $10 million to these plans during fiscal 2008.

8. Commitments and Contingencies

Litigation and Environmental Matters

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. We have responded timely to two sets of data requests received from the Commission and are fully cooperating with the Commission during this investigation.

Subsequent to responding to the second set of data requests, the Commission agreed to allow the Company to conduct our own internal investigation into compliance with the Commission's rules, and we will provide the results of this internal investigation to the Commission upon its completion. We currently are unable to predict the final outcome of this investigation or the potential impact it could have on our financial position, results of operations or cash flows.

On May 29, 2008, the Texas Railroad Commission adopted a rule effective September 1, 2008, which will be applicable to all natural gas utility companies operating in Texas concerning the replacement of compression couplings at pre-bent gas meter risers. Compliance with this rule will require us to expend significant amounts of capital. This will cause us to redirect a greater portion of our capital budget towards our Mid-Tex Division but these prudent and mandatory expenditures should be recoverable through our rates in this division. As a result, we anticipate no long-term adverse impact on our financial position, results of operations or cash flows.

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the year ended September 30, 2007, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2008. 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, 2008, AEM was committed to purchase 76.5 Bcf within one year, 38.4 Bcf within one to three years and 1.8 Bcf after three years under indexed contracts. AEM is committed to purchase 1.3 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $7.68 to $14.37. Purchases under these contracts totaled $842.1 million and $567.9 million for the three months ended June 30, 2008 and 2007 and $2,274.4 million and $1,551.3 million for the nine months ended June 30, 2008 and 2007.

Our natural gas distribution operations, other than the 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 its service area, which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of June 30, 2008 are as follows (in thousands):

2008	$ 71,430
2009	632,496
2010	164,008
2011	14,066
2012	12,878
Thereafter	16,124
	$911,002

Regulatory Matters

During the three months ended June 30, 2008, we concluded rate cases we had filed in our Kansas and Mid-Tex service areas. As of June 30, 2008, rate cases were in progress in our Georgia and Virginia service areas, and we were working with the intervenors to complete their review of the Mid-Tex Division's first Rate

Review Mechanism filing made in April 2008. 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 15 to the financial statements in our Annual Report on Form 10-K for the year ended September 30, 2007. During the nine months ended June 30, 2008, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage businesses as well as certain other nonregulated 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 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 and
- the pipeline, storage and other segment, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

In our determination of reportable segments, we consider 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, 2007. We evaluate performance based on net income or loss of the respective operating units.

As described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2007, we changed the composition of our operating segments. Effective September 2007, all prior period segment information has been restated to conform to our new segment presentation.

Income statements for the three and nine-month periods ended June 30, 2008 and 2007 by segment are presented in the following tables:

	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

	Three Months Ended June 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$548,104	$20,694	$649,633	$ (279)	$ —	$1,218,152
Intersegment revenues	147	16,013	204,534	2,352	(223,046)	—
	548,251	36,707	854,167	2,073	(223,046)	1,218,152
Purchased gas cost	357,608	—	854,743	228	(222,443)	990,136
Gross profit	190,643	36,707	(576)	1,845	(603)	228,016
Operating expenses						
Operation and maintenance	93,623	14,139	6,854	1,214	(689)	115,141
Depreciation and amortization	43,661	4,559	376	378	—	48,974
Taxes, other than income	50,005	2,288	295	293	—	52,881
Impairment of long-lived assets	3,289	—	—	—	—	3,289
Total operating expenses	190,578	20,986	7,525	1,885	(689)	220,285
Operating income (loss)	65	15,721	(8,101)	(40)	86	7,731
Miscellaneous income	2,232	620	1,578	3,992	(4,156)	4,266
Interest charges	28,987	6,720	2,012	830	(4,070)	34,479
Income (loss) before income taxes	(26,690)	9,621	(8,535)	3,122	—	(22,482)
Income tax expense (benefit)	(11,000)	3,459	(2,925)	1,344	—	(9,122)
Net income (loss)	$(15,690)	$ 6,162	$ (5,610)	$1,778	$ —	$ (13,360)
Capital expenditures	$ 78,829	$10,761	$ 187	$ 454	$ —	$ 90,231

	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

	Nine Months Ended June 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,973,048	$ 59,029	$1,844,271	$20,019	$ —	$4,896,367
Intersegment revenues	480	63,618	516,631	7,464	(588,193)	—
	2,973,528	122,647	2,360,902	27,483	(588,193)	4,896,367
Purchased gas cost	2,174,071	—	2,275,291	682	(585,971)	3,864,073
Gross profit	799,457	122,647	85,611	26,801	(2,222)	1,032,294
Operating expenses						
Operation and maintenance	284,064	37,594	19,022	4,173	(2,480)	342,373
Depreciation and amortization	133,287	13,400	1,153	1,195	—	149,035
Taxes, other than income	141,292	6,584	951	867	—	149,694
Impairment of long-lived assets	3,289	—	—	—	—	3,289
Total operating expenses	561,932	57,578	21,126	6,235	(2,480)	644,391
Operating income	237,525	65,069	64,485	20,566	258	387,903
Miscellaneous income	6,633	1,530	5,816	5,588	(11,884)	7,683
Interest charges	91,164	20,852	3,418	5,465	(11,626)	109,273
Income before income taxes	152,994	45,747	66,883	20,689	—	286,313
Income tax expense	60,530	16,661	26,515	8,201	—	111,907
Net income	$ 92,464	$ 29,086	$ 40,368	$12,488	$ —	$ 174,406
Capital expenditures	$ 222,526	$ 37,142	$ 837	$ 2,518	$ —	$ 263,023

Balance sheet information at June 30, 2008 and September 30, 2007 by segment is presented in the following tables:

	June 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	$3,398,317	$556,196	$ 7,546	$ 50,829	$ —	$4,012,888
Investment in subsidiaries	476,542	—	(2,096)	—	(474,446)	—
Current assets						
Cash and cash equivalents	32,949	—	13,308	244	—	46,501
Cash held on deposit in margin account	—	—	62,152	—	—	62,152
Assets from risk management activities	37,366	—	19,770	147	(14,383)	42,900
Other current assets	687,453	16,669	627,786	49,919	(136,422)	1,245,405
Intercompany receivables	490,979	—	—	203,115	(694,094)	—
Total current assets	1,248,747	16,669	723,016	253,425	(844,899)	1,396,958
Intangible assets	—	—	2,245	—	—	2,245
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	5,904	—	—	5,904
Deferred charges and other assets	203,663	9,477	1,228	17,451	—	231,819
	$5,895,044	$714,832	$762,125	$332,134	$(1,319,345)	$6,384,790
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,105,407	$124,055	$155,832	$196,655	$ (476,542)	$2,105,407
Long-term debt	2,119,140	—	—	589	—	2,119,729
Total capitalization	4,224,547	124,055	155,832	197,244	(476,542)	4,225,136
Current liabilities						
Current maturities of long-term debt	—	—	—	1,059	—	1,059
Short-term debt	113,257	—	41,000	17,275	(58,275)	113,257
Liabilities from risk management activities	—	—	50,822	14,247	(14,383)	50,686
Other current liabilities	635,200	6,078	343,238	95,290	(76,051)	1,003,755
Intercompany payables	—	536,235	157,859	—	(694,094)	—
Total current liabilities	748,457	542,313	592,919	127,871	(842,803)	1,168,757
Deferred income taxes	393,426	44,710	8,948	3,585	—	450,669
Noncurrent liabilities from risk management activities	—	—	3,724	—	—	3,724
Regulatory cost of removal obligation	280,108	—	—	—	—	280,108
Deferred credits and other liabilities	248,506	3,754	702	3,434	—	256,396
	$5,895,044	$714,832	$762,125	$332,134	$(1,319,345)	$6,384,790

	September 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,251,144	$531,921	$ 7,850	$ 45,921	$ —	$3,836,836
Investment in subsidiaries	396,474	—	(2,096)	—	(394,378)	—
Current assets						
Cash and cash equivalents	28,881	—	31,703	141	—	60,725
Cash held on deposit in margin account	—	—	—	—	—	—
Assets from risk management activities	—	—	26,783	12,947	(17,881)	21,849
Other current assets	643,353	20,065	337,169	76,731	(90,997)	986,321
Intercompany receivables	536,985	—	—	114,300	(651,285)	—
Total current assets	1,209,219	20,065	395,655	204,119	(760,163)	1,068,895
Intangible assets	—	—	2,716	—	—	2,716
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	5,535	—	—	5,535
Deferred charges and other assets	227,869	4,898	1,279	13,913	—	247,959
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,965,754	$ 88,719	$107,090	$200,665	$ (396,474)	$1,965,754
Long-term debt	2,125,007	—	—	1,308	—	2,126,315
Total capitalization	4,090,761	88,719	107,090	201,973	(396,474)	4,092,069
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,581	—	3,831
Short-term debt	187,284	—	30,000	—	(66,685)	150,599
Liabilities from risk management activities	21,053	—	18,167	—	(17,881)	21,339
Other current liabilities	519,642	6,394	186,792	53,297	(22,216)	743,909
Intercompany payables	—	550,184	101,101	—	(651,285)	—
Total current liabilities	729,229	556,578	336,060	55,878	(758,067)	919,678
Deferred income taxes	326,518	40,565	(8,925)	12,411	—	370,569
Noncurrent liabilities from risk management activities	—	—	290	—	—	290
Regulatory cost of removal obligation	271,059	—	—	—	—	271,059
Deferred credits and other liabilities	234,914	3,512	706	4,120	—	243,252
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2008, and the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2008 and 2007, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2008 and 2007. 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, 2007, 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 27, 2007, 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, 2007, 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, 2008

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, 2007.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar 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 year ended September 30, 2007, include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in one state; adverse weather conditions; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; the capital-intensive nature of our distribution business, increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the impact of environmental regulations on our business; the inherent hazards and risks involved in operating our distribution business, natural disasters, terrorist activities or other events; and other uncertainties, which may be discussed herein, including the outcome of any pending federal or state regulatory investigations, 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 Corporation 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.

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, 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 year ended September 30, 2007 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 by the Audit Committee quarterly. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2008.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2008 and 2007:

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
	(In thousands, except per share data)			
Operating revenues	$1,639,145	$1,218,152	$5,780,640	$4,896,367
Gross profit	246,222	228,016	1,050,254	1,032,294
Operating expenses	225,513	220,285	659,893	644,391
Operating income	20,709	7,731	390,361	387,903
Miscellaneous income	1,600	4,266	2,974	7,683
Interest charges	33,470	34,479	103,803	109,273
Income (loss) before income taxes	(11,161)	(22,482)	289,532	286,313
Income tax expense (benefit)	(4,573)	(9,122)	110,783	111,907
Net income (loss)	$ (6,588)	$ (13,360)	$ 178,749	$ 174,406
Diluted net income (loss) per share	$ (0.07)	$ (0.15)	$ 1.99	$ 2.00

Our consolidated net income (loss) during the three and nine months ended June 30, 2008 and 2007 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2008	2007	Change
	(In thousands)		
Natural gas distribution segment	$(12,378)	$(15,690)	$3,312
Regulated transmission and storage segment	10,265	6,162	4,103
Natural gas marketing segment	(6,314)	(5,610)	(704)
Pipeline, storage and other segment	1,839	1,778	61
Net loss	$ (6,588)	$(13,360)	$6,772

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands)		
Natural gas distribution segment	$113,442	$ 92,464	$ 20,978
Regulated transmission and storage segment	35,336	29,086	6,250
Natural gas marketing segment	19,565	40,368	(20,803)
Pipeline, storage and other segment	10,406	12,488	(2,082)
Net income	$178,749	$174,406	$ 4,343

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		
	2008	2007	Change
	(In thousands, except per share data)		
Regulated operations	$(2,113)	$ (9,528)	$7,415
Nonregulated operations	(4,475)	(3,832)	(643)
Consolidated net loss	$(6,588)	$(13,360)	$6,772
Diluted EPS from regulated operations	$ (0.02)	$ (0.11)	$ 0.09
Diluted EPS from nonregulated operations	(0.05)	(0.04)	(0.01)
Consolidated diluted EPS	$ (0.07)	$ (0.15)	$ 0.08

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands, except per share data)		
Regulated operations	$148,778	$121,550	$ 27,228
Nonregulated operations	29,971	52,856	(22,885)
Consolidated net income	$178,749	$174,406	$ 4,343
Diluted EPS from regulated operations	$ 1.66	$ 1.39	$ 0.27
Diluted EPS from nonregulated operations	0.33	0.61	(0.28)
Consolidated diluted EPS	$ 1.99	$ 2.00	$ (0.01)

The following summarizes the results of our operations and other significant events for the nine months ended June 30, 2008:

- Regulated operations generated 83 percent of net income during the nine months ended June 30, 2008 compared to 70 percent during the nine months ended June 30, 2007. The $27.2 million increase in our regulated operations net income primarily reflects rate increases in our Mid-Tex, Kansas, Kentucky, Louisiana, Tennessee and West Texas service areas coupled with higher rates and throughput in our Atmos Pipeline — Texas Division.
- Nonregulated operations contributed 17 percent of net income during the nine months ended June 30, 2008 compared to 30 percent during the nine months ended June 30, 2007. The $22.9 million decrease in our nonregulated operations net income primarily reflects lower asset optimization margins partially offset by higher delivered gas margins and higher unrealized gains.
- For the nine months ended June 30, 2008, we generated $417.4 million in operating cash flow compared with $552.7 million for the nine months ended June 30, 2007, primarily reflecting an increase in cash required to collateralize our risk management accounts.
- In September 2007, we filed a statement of intent seeking a rate increase of $51.9 million in our Mid-Tex Division. During the fiscal 2008 second quarter, we reached a settlement agreement with approximately 80 percent of the Mid-Tex Division's customers. In June 2008, the Railroad Commission of Texas (RRC) issued a final order, which ended the case for the remaining 20 percent of the Mid-Tex Division's customers.

Three Months Ended June 30, 2008 compared with Three Months Ended June 30, 2007

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. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

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.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2008 and 2007 are presented below.

	Three Months Ended June 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	$199,928	$190,643	$ 9,285
Operating expenses	194,731	190,578	4,153
Operating income	5,197	65	5,132
Miscellaneous income	3,508	2,232	1,276
Interest charges	28,504	28,987	(483)
Loss before income taxes	(19,799)	(26,690)	6,891
Income tax benefit	(7,421)	(11,000)	3,579
Net loss	$(12,378)	$(15,690)	$ 3,312
Consolidated natural gas distribution sales volumes — MMcf	41,357	45,252	(3,895)
Consolidated natural gas distribution transportation volumes — MMcf	32,126	29,311	2,815
Total consolidated natural gas distribution throughput — MMcf	73,483	74,563	(1,080)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.43	$ 0.41	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 11.53	$ 7.90	$ 3.63

The following table shows our operating income by natural gas distribution division for the three months ended June 30, 2008 and 2007. 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		
	2008	2007	Change
	(In thousands)		
Colorado-Kansas	$ 542	$ 884	$ (342)
Kentucky/Mid-States	5,757	1,762	3,995
Louisiana	5,086	5,921	(835)
Mid-Tex	(3,043)	(11,415)	8,372
Mississippi	(946)	2,115	(3,061)
West Texas	(563)	(391)	(172)
Other	(1,636)	1,189	(2,825)
Total	$ 5,197	$ 65	$ 5,132

The $9.3 million increase in natural gas distribution gross profit primarily reflects an $8.9 million increase in rates. The increase in rates primarily was attributable to the Mid-Tex Division, which increased $5.0 million as a result of the 2006 Gas Reliability Infrastructure Program (GRIP) filing, the current year Mid-Tex rate case and the absence of a one-time GRIP refund in the prior year. The current-year period also reflects $3.9 million in rate increases in our Kansas, Kentucky, Louisiana, Missouri, Tennessee and West Texas service areas.

Gross profit also increased approximately $0.4 million in revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This increase, offset by a $2.9 million quarter-over-quarter increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $2.5 million decrease 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 and taxes, other than income, increased $4.2 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $2.3 million, primarily due to an overall increase in administrative costs.

Depreciation and amortization expense increased $1.1 million for the third quarter of fiscal 2008 compared with third quarter of fiscal 2007. The increase primarily was attributable to increases in assets placed in service during the current year.

Operating expenses for the prior-year quarter also include a $3.3 million noncash charge associated with the write-off of software costs.

Interest charges allocated to the natural gas distribution segment decreased $0.5 million due to lower average effective interest rates experienced during the current-year quarter compared to the prior-year quarter.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2008 are discussed below. The amounts described below represent the gross revenues that were requested or received in each rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

<u>Mid-Tex Division Rate Case</u>

In September 2007, Atmos Energy filed a statement of intent seeking a system-wide rate increase of $51.9 million in our Mid-Tex Division. During the fiscal 2008 second quarter, we reached a settlement with 438 of the 439 cities (the "Settlement Cities"), which represent approximately 80 percent of the Mid-Tex Division's customers. The settlement agreement includes i) an annual system-wide rate increase of approximately $10 million, of which approximately $8 million related to the Settlement Cities; ii) the ability to recover the gas cost portion of bad debt expense, iii) a rate review mechanism (RRM) that will adjust rates for the Settlement Cities annually to reflect changes in the Mid-Tex Division's cost of service and rate base; iv) an authorized return on equity of 9.6 percent; v) an approved capital structure of 52 percent debt/48 percent equity and vi) the establishment of a new program designed to encourage natural gas conservation. New rates for the Settlement Cities were implemented April 1, 2008.

In April 2008, the Mid-Tex Division filed its first RRM that will adjust rates, effective October 1, 2008, for the Settlement Cities only. The filing seeks an annual system-wide rate increase of $33.5 million ($26.8 million for the Settlement Cities) and is currently under review.

The City of Dallas and unincorporated areas, which represent the remaining 20 percent of the Mid-Tex Division's customers, elected not to participate in the settlement agreement. The Mid-Tex Division, the City of Dallas and representatives for the unincorporated areas conducted a full rate case before the Railroad Commission of Texas (RRC), culminating in the issuance of a final order in June 2008. Key terms of the final order include i) a $19.6 million system-wide annual rate increase, of which approximately $3.9 million related to the City of Dallas and unincorporated areas, ii) the ability to recover the gas cost portion of bad debt expense, iii) an authorized return on equity of 10 percent; iv) an approved capital structure of 52 percent debt/48 percent equity and v) the establishment of a new program designed to encourage natural gas conservation. New rates for the City of Dallas and the unincorporated areas were implemented in July 2008.

The final order did not include an RRM; therefore, we will continue to make annual filings under the Texas Gas Reliability Infrastructure Program (GRIP) in order to update rates for customers in the City of

Dallas and in the unincorporated areas for approved capital expenditures, and we will continue to file traditional rate cases as necessary to assist in earning our authorized return in these areas.

In May 2008, the Mid-Tex Division filed a system-wide 2007 GRIP filing with the RRC. The filing seeks authorization to increase annual rates, on a system-wide basis by $10.3 million based on $58.2 million of capital costs incurred in 2007. It is currently anticipated that the RRC will issue a final order in this proceeding by November 2008. If approved as filed, the filing should result in an annual rate increase of approximately $2 million for customers in the City of Dallas and the unincorporated areas.

Other Rate Case Filings

In May 2006, Atmos Energy began receiving "show cause" ordinances from several of the cities in the West Texas Division. In December 2007, our West Texas Division reached a settlement agreement with the West Texas cities, resulting in an approved GRIP filing to include in rate base approximately $7.0 million of capital costs incurred during calendar year 2006. The filing should result in additional annual revenues of approximately $1.1 million.

In July 2008, the West Texas cities signed an agreement to implement a rate review mechanism for our West Texas system. The RRM will adjust rates on a periodic basis to reflect changes in the West Texas Division's cost of service and rate base for this service area. The West Texas Division expects to file its first RRM in September 2008, which will adjust rates for the West Texas cities effective November 15, 2008.

In May 2008, the City of Lubbock approved its Conservation and Customer Value Plan (CCVP), which contains an annual rate review mechanism that would adjust rates to reflect changes in the West Texas Division's cost of service and rate base. The West Texas Division filed its annual review filing under the CCVP in June 2008, which is currently under review by the City of Lubbock. The filing recommends a $0.5 million decrease in annual rates, and is expected to become effective October 1, 2008.

In October 2007, our Kentucky/Mid-States Division settled its $11.1 million rate case filed in May 2007 with the Tennessee Regulatory Authority. The settlement resulted in an increase in annual revenues of $4.0 million and a $4.1 million reduction in depreciation expense.

In September 2007, we filed an application with the Kansas Corporation Commission (KCC) requesting a rate increase of $5.0 million in our Kansas service area. A final order adopting the Company's settlement with the KCC Staff was issued in May 2008 resulting in an increase in annual revenues of $2.1 million.

In February 2008, we filed for an annual rate increase of $0.9 million in the Virginia jurisdiction of our Kentucky/Mid-States Division. New rates, subject to refund, were implemented in April 2008. A procedural schedule has been established that should result in a final order being issued by the fourth quarter of fiscal year 2008.

In March 2008, we filed for an annual rate increase of $6.2 million in the Georgia jurisdiction of our Kentucky/Mid-States Division. The first round of hearings was completed in July 2008. A procedural schedule has been established that should result in a final order being issued by the fourth quarter of fiscal year 2008.

Stable Rate Filings

Louisiana Division. In December 2007, we filed our TransLa annual rate stabilization clause with the Louisiana Public Service Commission requesting an increase of $2.2 million, including an increase in depreciation expense of approximately $0.4 million. The filing was for the test year ended September 30, 2007. The TransLa filing was approved in March 2008 and resulted in an increase of $2.1 million in annual revenues effective April 1, 2008. In April 2008, we filed the LGS annual rate stabilization clause, requesting an increase of $2.6 million. The filing was for the test year ended December 31, 2007. The LGS filing was approved in June 2008 and resulted in an increase of $1.7 million in annual revenues effective July 1, 2008.

Mississippi Division. In December 2007, the Mississippi Public Service Commission approved our annual stable rate filing with no change in rates.

Regulated Transmission and Storage Segment

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

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2008 and 2007 are presented below.

	Three Months Ended June 30		
	2008	**2007**	**Change**
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 18,761	$ 15,718	$ 3,043
Third-party transportation	22,485	16,807	5,678
Storage and park and lend services	2,387	1,893	494
Other	2,653	2,289	364
Gross profit	46,286	36,707	9,579
Operating expenses	24,395	20,986	3,409
Operating income	21,891	15,721	6,170
Miscellaneous income	550	620	(70)
Interest charges	6,606	6,720	(114)
Income before income taxes	15,835	9,621	6,214
Income tax expense	5,570	3,459	2,111
Net income	$ 10,265	$ 6,162	$ 4,103
Gross pipeline transportation volumes — MMcf	181,112	157,825	23,287
Consolidated pipeline transportation volumes — MMcf	152,450	125,639	26,811

The $9.6 million increase in gross profit primarily was attributable to a $4.4 million increase from rate adjustments resulting from our 2006 and 2007 GRIP filings and a $2.5 million increase from transportation volumes. Consolidated throughput increased 21 percent, primarily due to increased transportation in the Barnett Shale region of Texas. The improvement in gross profit also reflects $1.5 million of increased per-unit transportation margins due to favorable market conditions.

Operating expenses increased $3.4 million primarily due to increased pipeline integrity and maintenance costs.

Recent Ratemaking Developments

In April 2008, the RRC approved the GRIP filing for our Atmos Pipeline — Texas Division to include in rate base approximately $46.6 million of capital costs incurred during calendar year 2007. The filing should result in additional annual revenues of approximately $7.0 million. These revenues represent the gross revenues that were received in the filing, which may not necessarily result in an equal increase in operating income, as some operating costs may increase.

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 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 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 ones 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, 2008 and 2007 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 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		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 11,231	$ 9,999	$ 1,232
Asset optimization	(37,551)	(33,376)	(4,175)
	(26,320)	(23,377)	(2,943)
Unrealized margins	23,689	22,801	888
Gross profit	(2,631)	(576)	(2,055)
Operating expenses	5,205	7,525	(2,320)
Operating loss	(7,836)	(8,101)	265
Miscellaneous income	377	1,578	(1,201)
Interest charges	2,850	2,012	838
Loss before income taxes	(10,309)	(8,535)	(1,774)
Income tax benefit	(3,995)	(2,925)	(1,070)
Net loss	$ (6,314)	$ (5,610)	$ (704)
Gross natural gas marketing sales volumes — MMcf	103,403	104,783	(1,380)
Consolidated natural gas marketing sales volumes — MMcf	82,122	85,413	(3,291)
Net physical position (Bcf)	17.5	21.5	(4.0)

The $2.1 million decrease in our natural gas marketing segment's gross profit primarily reflects a $4.2 million decrease in realized asset optimization margins. Natural gas market conditions were significantly less volatile during the current-year compared with the prior-year, which created fewer opportunities to realize arbitrage gains. During the quarter, AEM elected to defer storage withdrawals and reset the corresponding financial instruments in order to increase, in future periods, the potential gross profit it could realize from its asset optimization activities. As a result, AEM realized settlement losses without corresponding storage withdrawal gains in the current quarter. In the prior year, AEM accelerated the withdrawal of physical gas into the fiscal 2007 second quarter and executed new financial instruments to hedge the original financial instruments. The losses incurred on the settlement of these financial instruments in the prior-year quarter were smaller than the settlement losses experienced in the current quarter.

The increased loss generated from realized asset optimization activities was partially offset by a $1.2 million increase in realized delivered gas margins. The increase was largely attributable to slightly higher per-unit margins, compared with the prior-year quarter, partially offset by slightly lower sales volumes.

Gross profit margin was also favorably impacted by a $0.9 million increase in unrealized margins attributable to a narrowing of the spreads between current cash prices and forward natural gas prices. The change in unrealized margins also reflects the recognition of previously unrealized margins as a component of realized margins as a result of injecting and withdrawing gas and settling financial instruments as a part of AEM's asset optimization activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, decreased $2.3 million primarily due to a decrease in employee 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 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, 2008, March 31, 2008, December 31, 2007 and September 30, 2007.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gain (Loss)	Potential Gross Profit(1)
	(Bcf)	(In millions)	(In millions)	(In millions)
June 30, 2008	17.5	$48.2	$34.3	$13.9
March 31, 2008	20.7	$10.8	$ (0.6)	$11.4
December 31, 2007	17.7	$44.2	$32.9	$11.3
September 30, 2007	12.3	$40.8	$10.8	$30.0

(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 a more comprehensive view to investors 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, 2008, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $48.2 million. This amount will be reduced by $34.3 million of net unrealized gains recorded in the financial statements as of June 30, 2008 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit was $13.9 million at June 30, 2008.

The $2.5 million increase in potential gross profit as compared to March 31, 2008, is comprised of a $37.4 million increase in the economic gross profit, principally due to the election to roll positions into forward months as described above, partially offset by a $34.9 million increase in unrealized gains primarily attributable to recognizing as a component of realized margin previously unrealized losses and a favorable movement in the market prices used to value our natural gas storage inventory.

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, 2008 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, 2008, without encountering operational or other issues, we anticipate a portion of the potential gross profit as of June 30, 2008 will be recognized during the final quarter of fiscal 2008 with most of the remainder recognized during fiscal 2009.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by Atmos Energy Holdings, Inc.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of June 30, 2008, these activities were limited in nature.

AES, through December 31, 2006, provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our natural gas distribution service areas at competitive prices. Effective January 1, 2007, these services were moved to our shared services function included in our natural gas distribution segment. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Results for this segment are primarily impacted 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, 2008 and 2007 are presented below.

	Three Months Ended June 30		
	2008	2007	Change
	(In thousands)		
Storage and transportation services	$ 3,691	$ 4,060	$ (369)
Asset optimization	(1,329)	(2,247)	918
Other	1,210	845	365
Unrealized margins	(398)	(813)	415
Gross profit	3,174	1,845	1,329
Operating expenses	1,803	1,885	(82)
Operating income (loss)	1,371	(40)	1,411
Miscellaneous income	2,273	3,992	(1,719)
Interest charges	532	830	(298)
Income before income taxes	3,112	3,122	(10)
Income tax expense	1,273	1,344	(71)
Net income	$ 1,839	$ 1,778	$ 61

Pipeline, storage and other gross profit increased $1.3 million primarily due to a $0.9 million increase in asset optimization margins as a result of a more favorable settlement of our asset management contracts in the current-year period. This increase was coupled with a $0.4 million increase in unrealized margins associated with asset optimization activities.

Operating expenses for the three months ended June 30, 2008 were consistent with the prior-year quarter.

Nine Months Ended June 30, 2008 compared with Nine Months Ended June 30, 2007

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, 2008 and 2007 are presented below.

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	$830,652	$799,457	$31,195
Operating expenses	564,440	561,932	2,508
Operating income	266,212	237,525	28,687
Miscellaneous income	7,654	6,633	1,021
Interest charges	88,802	91,164	(2,362)
Income before income taxes	185,064	152,994	32,070
Income tax expense	71,622	60,530	11,092
Net income	$113,442	$ 92,464	$20,978
Consolidated natural gas distribution sales volumes — MMcf	261,692	265,508	(3,816)
Consolidated natural gas distribution transportation volumes — MMcf	105,605	101,572	4,033
Total consolidated natural gas distribution throughput — MMcf	367,297	367,080	217
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.44	$ 0.46	$ (0.02)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 8.77	$ 8.19	$ 0.58

The following table shows our operating income by natural gas distribution division for the nine months ended June 30, 2008 and 2007. 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		
	2008	2007	Change
	(In thousands)		
Colorado-Kansas	$ 22,766	$ 24,524	$ (1,758)
Kentucky/Mid-States	49,800	44,913	4,887
Louisiana	36,254	39,540	(3,286)
Mid-Tex	119,661	82,932	36,729
Mississippi	23,397	25,918	(2,521)
West Texas	13,332	18,230	(4,898)
Other	1,002	1,468	(466)
Total	$266,212	$237,525	$28,687

The $31.2 million increase in natural gas distribution gross profit primarily reflects a $31.7 million net increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division which increased $24.1 million as a result of the 2006 GRIP filing, the previous and current year Mid-Tex rate cases and the absence of a one time GRIP refund in the prior year. The current-year period also reflects $10.7 million in rate increases in our Kansas, Kentucky, Louisiana, Tennessee and West Texas service areas.

Gross profit also increased approximately $6.5 million in revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current-year period compared to the prior-year period. This increase, partially offset by a $2.5 million period-over-period increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $4.0 million increase 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 and taxes, other than income, increased by $2.5 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $11.1 million, primarily due to increased administrative and natural gas odorization costs partially offset by lower employee costs. The increase in operation and maintenance expense also reflects the absence in the current-year period of a nonrecurring $4.3 million deferral of hurricane-related operation and maintenance expenses in the prior-year period.

The provision for doubtful accounts decreased $3.5 million to $10.2 million for the nine months ended June 30, 2008. The decrease primarily was attributable to strong collection efforts.

Depreciation and amortization expense decreased $2.6 million for the nine months ended June 30, 2008 compared with the nine months ended June 30, 2007. The decrease primarily was attributable to changes in depreciation rates as a result of recent rate cases.

Operating expenses for the prior-year period also include a $3.3 million noncash charge associated with the write-off of software costs.

Results for the current-year period include a $1.2 million gain on the sale of irrigation assets in our West Texas Division during the fiscal 2008 second quarter.

Interest charges allocated to the natural gas distribution segment decreased $2.4 million due to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period.

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, 2008 and 2007 are presented below.

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 69,409	$ 62,149	$ 7,260
Third-party transportation	58,946	45,162	13,784
Storage and park and lend services	6,288	6,943	(655)
Other	8,129	8,393	(264)
Gross profit	142,772	122,647	20,125
Operating expenses	68,565	57,578	10,987
Operating income	74,207	65,069	9,138
Miscellaneous income	933	1,530	(597)
Interest charges	20,453	20,852	(399)
Income before income taxes	54,687	45,747	8,940
Income tax expense	19,351	16,661	2,690
Net income	$ 35,336	$ 29,086	$ 6,250
Gross pipeline transportation volumes — MMcf	593,452	528,144	65,308
Consolidated pipeline transportation volumes — MMcf	429,758	359,447	70,311

The $20.1 million increase in gross profit primarily was attributable to a $10.0 million increase from rate adjustments resulting from our 2006 and 2007 GRIP filings and a $6.1 million increase from transportation volumes. Consolidated throughput increased 20 percent primarily due to increased transportation in the Barnett Shale region of Texas. The improvement in gross profit also reflects increased service fees and per-unit transportation margins due to favorable market conditions which contributed $3.6 million. New compression contracts and transportation capacity enhancements also contributed $2.4 million. These increases were partially offset by a $1.6 million decrease in sales of excess gas compared to the same period in the prior year and a $1.0 million decrease in parking and lending services due to market conditions.

Operating expenses increased $11.0 million primarily due to increased pipeline integrity and maintenance costs.

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, 2008 and 2007 are presented below.

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 55,599	$ 44,320	$ 11,279
Asset optimization	(10,339)	38,558	(48,897)
	45,260	82,878	(37,618)
Unrealized margins	14,404	2,733	11,671
Gross profit	59,664	85,611	(25,947)
Operating expenses	22,775	21,126	1,649
Operating income	36,889	64,485	(27,596)
Miscellaneous income	1,775	5,816	(4,041)
Interest charges	6,166	3,418	2,748
Income before income taxes	32,498	66,883	(34,385)
Income tax expense	12,933	26,515	(13,582)
Net income	$ 19,565	$ 40,368	$(20,803)
Gross natural gas marketing sales volumes — MMcf	348,789	306,931	41,858
Consolidated natural gas marketing sales volumes — MMcf	298,351	264,325	34,026
Net physical position (Bcf)	17.5	21.5	(4.0)

The $25.9 million decrease in our natural gas marketing segment's gross profit primarily reflects a $48.9 million decrease in realized asset optimization margins. As a result of a less volatile natural gas market experienced during the year, AEM has been regularly deferring storage withdrawals and resetting the associated financial instruments to increase the potential gross profit it could realize from its asset optimization activities in future periods. As a result, AEM recognized settlement losses without corresponding storage withdrawal gains during the current fiscal year. Additionally, AEM experienced increased storage fees charged by third parties during this time period. In the prior year, AEM was able to recognize arbitrage gains as changes in its originally scheduled storage injection and withdrawal plans had a significantly smaller impact.

The decrease in realized asset optimization margins was partially offset by an $11.3 million increase in realized delivered gas margins. The increase reflects both increased sales volumes and increased per-unit margins. Gross sales volumes increased 14 percent compared with the prior-year period as we were able to successfully execute our marketing initiatives. The increase in the per-unit margin primarily reflects favorable basis gains on certain contracts. After excluding the effect of these location basis gains, our per-unit margins decreased four percent in the current-year period due to increased competition experienced during the third fiscal quarter in a higher-priced natural gas market.

Gross profit margin was also favorably impacted by an $11.7 million increase in unrealized margins attributable to a narrowing of the spreads between current cash prices and forward natural gas prices. The change in unrealized margins also reflects the recognition of previously unrealized margins as a component of realized margins as a result of injecting and withdrawing gas and settling financial instruments as a part of AEM's asset optimization activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $1.6 million. The increase reflects $2.4 million for the settlement of certain tax matters partially offset by a $0.8 million decrease in employee and other administrative costs.

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, 2008 and 2007 are presented below.

	Nine Months Ended June 30		
	2008	2007	Change
	(In thousands)		
Storage and transportation services	$11,325	$11,850	$ (525)
Asset optimization	3,783	10,947	(7,164)
Other	3,701	2,992	709
Unrealized margins	47	1,012	(965)
Gross profit	18,856	26,801	(7,945)
Operating expenses	6,061	6,235	(174)
Operating income	12,795	20,566	(7,771)
Miscellaneous income	6,243	5,588	655
Interest charges	1,755	5,465	(3,710)
Income before income taxes	17,283	20,689	(3,406)
Income tax expense	6,877	8,201	(1,324)
Net income	$10,406	$12,488	$(2,082)

Pipeline, storage and other gross profit decreased $7.9 million primarily due to a $7.2 million decrease in asset optimization margins as a result of a less volatile natural gas market. The change in gross profit also reflects a decrease of $1.0 million in unrealized margins associated with asset optimization activities.

Operating expenses for the nine months ended June 30, 2008 remained generally unchanged compared with the prior-year period.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds and borrowings under our credit facilities and commercial paper program. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

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, 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, 2008, we generated operating cash flow of $417.4 million from operating activities compared with $552.7 million for the nine months ended June 30, 2007. Period over period, our operating cash flow was reduced primarily by cash required to collateralize our risk management accounts, which reduced operating cash flows by $84.2 million. Additionally, changes in accounts receivable and gas stored underground reduced operating cash flow by $219.9 million. These decreases were partially offset by favorable timing of accounts payable and accrued liabilities which increased operating cash flow by $141.8 million. Finally, other changes in working capital and other items increased operating cash flow by $27.0 million.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund acquisitions and growth projects, our ongoing construction program and improvements to information 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, 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 2008 are expected to range from $455 million to $465 million. For the nine months ended June 30, 2008, we incurred $312.9 million for capital expenditures compared with $263.0 million for the nine months ended June 30, 2007. The increase in capital spending primarily reflects an increase in main replacements in our Mid-Tex Division and spending in the natural gas distribution segment for our new automated metering initiative. This initiative is expected to improve the efficiency of our meter reading process through the installation of equipment that automatically reads and transfers customer consumption and other data to our customer information systems.

Cash flows from financing activities

For the nine months ended June 30, 2008, our financing activities reflected a use of cash of $114.4 million compared with $5.2 million in the prior-year period. Our significant financing activities for the nine months ended June 30, 2008 and 2007 are summarized as follows.

- During the nine months ended June 30, 2008, we repaid a net $35.7 million under our short-term credit facilities. The net repayment reflects the timing of the use of our line of credit to finance natural gas purchases.
- We repaid $9.9 million of long-term debt during the nine months ended June 30, 2008 compared with $2.7 million during the nine months ended June 30, 2007. The increased payments during the current-year period reflects the prepayment of $7.5 million of our Series P First Mortgage Bonds. In connection with this prepayment we paid a $0.2 million make-whole premium in accordance with the terms of the bonds and related indenture.
- In December 2006, we sold 6.3 million shares of common stock in an offering, including the underwriters' exercise of their overallotment option of 0.8 million shares, generating net proceeds of approximately $192 million. The net proceeds from this issuance were used to reduce our short-term debt.
- During the nine months ended June 30, 2008, we paid $87.8 million in cash dividends compared with $83.1 million for the nine months ended June 30, 2007. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.96 per share during the nine months

ended June 30, 2007 to $0.975 per share during the nine months ended June 30, 2008 combined with our December 2006 equity offering and new share issuances under our various equity plans.

- During the nine months ended June 30, 2008, we issued 0.7 million shares of common stock under our various equity plans which generated net proceeds of $19.1 million. In addition, we granted 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, 2008 and 2007.

	Nine Months Ended June 30	
	2008	2007
Shares issued:		
Direct Stock Purchase Plan	294,071	238,689
Retirement Savings Plan	410,350	306,920
1998 Long-Term Incentive Plan	538,100	500,684
Outside Directors Stock-for-Fee Plan	2,399	1,776
Public Offering	—	6,325,000
Total shares issued	1,244,920	7,373,069

Credit Facilities

As of June 30, 2008, we had a total of approximately $1.5 billion of credit facilities, comprised of three short-term committed credit facilities totaling $918 million and, through AEM, an uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

As of June 30, 2008, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1.0 billion. We believe these credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed consolidated financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of June 30, 2008, we had approximately $450 million available for issuance under the registration statement. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

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). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P maintains its positive outlook and Fitch maintains its stable outlook. Moody's recently reaffirmed its stable outlook. None of our ratings are currently under review.

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, 2008. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization as of June 30, 2008, September 30, 2007 and June 30, 2007:

	June 30, 2008		September 30, 2007		June 30, 2007	
	(In thousands, except percentages)					
Short-term debt	$ 113,257	2.6%	$ 150,599	3.5%	$ —	—%
Long-term debt	2,120,788	48.9%	2,130,146	50.2%	2,430,518	55.0%
Shareholders' equity	2,105,407	48.5%	1,965,754	46.3%	1,988,142	45.0%
Total capitalization	$4,339,452	100.0%	$4,246,499	100.0%	$4,418,660	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.5 percent at June 30, 2008, 53.7 percent at September 30, 2007 and 55.0 percent at June 30, 2007. 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, 2008.

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. Pending regulatory approval, the first cavern is projected to go into operation by mid-2011, with the other two caverns projected to be operational by 2012 and 2014. Based on market demand, four additional storage caverns could potentially be developed.

Risk Management Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, 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 fair value hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings. In addition, natural gas inventory would be reflected on the balance sheet at the lower of cost or market instead of at fair value.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our natural gas distribution and natural gas marketing commodity derivative contracts for the three and nine months ended June 30, 2008 and 2007:

	Three Months Ended June 30, 2008		Three Months Ended June 30, 2007	
	Natural Gas Distribution	Natural Gas Marketing	Natural Gas Distribution	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$ 9,505	$(22,975)	$ 3,802	$(24,994)
Contracts realized/settled	339	30,185	(144)	15,994
Fair value of new contracts	5,675	—	(5,797)	—
Other changes in value	21,847	(50,182)	(5,385)	24,898
Fair value of contracts at end of period	$37,366	$(42,972)	$(7,524)	$ 15,898

	Nine Months Ended June 30, 2008		Nine Months Ended June 30, 2007	
	Natural Gas Distribution	Natural Gas Marketing	Natural Gas Distribution	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(21,053)	$ 26,808	$(27,209)	$ 15,003
Contracts realized/settled	(26,971)	(11,071)	(27,662)	(10,593)
Fair value of new contracts	5,395	—	(7,058)	—
Other changes in value	79,995	(58,709)	54,405	11,488
Fair value of contracts at end of period	$ 37,366	$(42,972)	$ (7,524)	$ 15,898

The fair value of our natural gas distribution and natural gas marketing derivative contracts at June 30, 2008, is segregated below by time period and fair value source:

	Fair Value of Contracts at June 30, 2008				
	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	$(7,511)	$2,373	$—	$—	$(5,138)
Prices based on models and other valuation methods	(275)	(193)	—	—	(468)
Total Fair Value	$(7,786)	$2,180	$—	$—	$(5,606)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2008 and 2007, our total net periodic pension and other benefits cost was $35.9 million and $36.4 million. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our total net periodic pension and other benefit costs remained relatively unchanged during the current-year period when compared with the prior-year period as the assumptions we made during our annual pension plan valuation completed June 30, 2007 were consistent with the prior year. 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. At our June 30, 2007 measurement date, the interest rates were consistent with rates at our prior-year measurement date, which resulted in no change to our 6.30 percent discount rate used to determine our fiscal 2008 net periodic and post-retirement cost. In addition, our expected return on our pension plan assets remained constant at 8.25 percent.

We are currently in the process of completing our fiscal 2008 pension plan valuation. Based upon market conditions as of the June 30, 2008 valuation date, we expect no significant increase in our fiscal 2009 net periodic pension cost.

During the nine months ended June 30, 2008, we contributed $6.7 million to our other postretirement plans, and we expect to contribute a total of approximately $10 million to these plans during fiscal 2008.

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, 2008 and 2007.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2008	2007	2008	2007
METERS IN SERVICE, end of period				
Residential	2,922,415	2,900,716	2,922,415	2,900,716
Commercial	271,542	274,273	271,542	274,273
Industrial	2,265	2,739	2,265	2,739
Public authority and other	9,234	16,576	9,234	16,576
Total meters	3,205,456	3,194,304	3,205,456	3,194,304
INVENTORY STORAGE BALANCE — Bcf	41.7	43.9	41.7	43.9
HEATING DEGREE DAYS[1]				
Actual (weighted average)	174	163	2,810	2,873
Percent of normal	102%	98%	100%	101%
SALES VOLUMES — MMcf[2]				
Gas sales volumes				
Residential	18,584	21,421	151,549	155,021
Commercial	15,199	16,672	82,325	83,231
Industrial	4,687	5,248	17,899	18,551
Public authority and other	2,887	1,911	9,919	8,705
Total gas sales volumes	41,357	45,252	261,692	265,508
Transportation volumes	33,211	30,431	109,002	105,125
Total throughput	74,568	75,683	370,694	370,633
OPERATING REVENUES (000's)[2]				
Gas sales revenues				
Residential	$ 352,893	$ 294,756	$1,878,855	$1,795,124
Commercial	213,594	170,425	903,771	855,468
Industrial	53,843	44,345	167,154	162,621
Public authority and other	33,135	18,193	100,983	84,550
Total gas sales revenues	653,465	527,719	3,050,763	2,897,763
Transportation revenues	14,163	12,040	46,954	46,997
Other gas revenues	9,011	8,492	28,955	28,768
Total operating revenues	$ 676,639	$ 548,251	$3,126,672	$2,973,528
Average transportation revenue per Mcf	$ 0.43	$ 0.40	$ 0.43	$ 0.45
Average cost of gas per Mcf sold	$ 11.53	$ 7.90	$ 8.77	$ 8.19

See footnotes following these tables.

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	
	2008	2007	2008	2007
CUSTOMERS, end of period				
Industrial	702	700	702	700
Municipal	56	64	56	64
Other	503	424	503	424
Total	1,261	1,188	1,261	1,188
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	18.8	25.1	18.8	25.1
Pipeline, storage and other	1.2	1.9	1.2	1.9
Total	20.0	27.0	20.0	27.0
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	181,112	157,825	593,452	528,144
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	103,403	104,783	348,789	306,931
OPERATING REVENUES (000's)(2)				
Regulated transmission and storage	$ 46,286	$ 36,707	$ 142,772	$ 122,647
Natural gas marketing	1,189,722	854,167	3,159,092	2,360,902
Pipeline, storage and other	3,880	2,073	20,629	27,483
Total operating revenues	$1,239,888	$892,947	$3,322,493	$2,511,032

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Generally, normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the year ended September 30, 2007. During the nine months ended June 30, 2008, there were no material changes in our quantitative and qualitative disclosures about market risk.

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

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of June 30, 2008. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed by the Company in the reports we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the nine months ended June 30, 2008, 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 environmental-related matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the year ended September 30, 2007. 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.

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.

SIGNATURES

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/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 6, 2008

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number
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.

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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2008

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of April 25, 2008.

Class	Shares Outstanding
No Par Value	90,188,545

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KCC	Kansas Corporation Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2008	September 30, 2007
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,518,436	$5,396,070
Less accumulated depreciation and amortization	1,569,570	1,559,234
Net property, plant and equipment	3,948,866	3,836,836
Current assets		
Cash and cash equivalents	139,636	60,725
Cash held on deposit in margin account	29,591	—
Accounts receivable, net	805,940	380,133
Gas stored underground	421,980	515,128
Other current assets	95,567	112,909
Total current assets	1,492,714	1,068,895
Goodwill and intangible assets	737,380	737,692
Deferred charges and other assets	242,034	253,494
	$6,420,994	$5,896,917
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2008 — 90,143,376 shares; September 30, 2007 — 89,326,537 shares	$ 451	$ 447
Additional paid-in capital	1,722,056	1,700,378
Retained earnings	407,464	281,127
Accumulated other comprehensive loss	(3,978)	(16,198)
Shareholders' equity	2,125,993	1,965,754
Long-term debt	2,119,696	2,126,315
Total capitalization	4,245,689	4,092,069
Current liabilities		
Accounts payable and accrued liabilities	809,140	355,255
Other current liabilities	408,575	409,993
Short-term debt	—	150,599
Current maturities of long-term debt	8,453	3,831
Total current liabilities	1,226,168	919,678
Deferred income taxes	420,232	370,569
Regulatory cost of removal obligation	277,560	271,059
Deferred credits and other liabilities	251,345	243,542
	$6,420,994	$5,896,917

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2008	2007
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,521,856	$1,461,033
Regulated transmission and storage segment	51,440	46,068
Natural gas marketing segment	1,128,653	795,041
Pipeline, storage and other segment	10,022	14,077
Intersegment eliminations	(227,986)	(240,637)
	2,483,985	2,075,582
Purchased gas cost		
Natural gas distribution segment	1,164,332	1,114,787
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,112,321	771,988
Pipeline, storage and other segment	338	229
Intersegment eliminations	(227,400)	(240,108)
	2,049,591	1,646,896
Gross profit	434,394	428,686
Operating expenses		
Operation and maintenance	120,053	111,862
Depreciation and amortization	48,790	51,066
Taxes, other than income	54,408	56,746
Total operating expenses	223,251	219,674
Operating income	211,143	209,012
Miscellaneous income	1,467	1,838
Interest charges	33,516	35,262
Income before income taxes	179,094	175,588
Income tax expense	67,560	69,083
Net income	$ 111,534	$ 106,505
Basic net income per share	$ 1.25	$ 1.21
Diluted net income per share	$ 1.24	$ 1.20
Cash dividends per share	$ 0.325	$ 0.320
Weighted average shares outstanding:		
Basic	89,314	88,078
Diluted	89,990	88,735

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31 2008	Six Months Ended March 31 2007
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,450,033	$2,425,277
Regulated transmission and storage segment	96,486	85,940
Natural gas marketing segment	1,969,370	1,506,735
Pipeline, storage and other segment	16,749	25,410
Intersegment eliminations	(391,143)	(365,147)
	4,141,495	3,678,215
Purchased gas cost		
Natural gas distribution segment	1,819,309	1,816,463
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,907,075	1,420,548
Pipeline, storage and other segment	1,067	454
Intersegment eliminations	(389,988)	(363,528)
	3,337,463	2,873,937
Gross profit	804,032	804,278
Operating expenses		
Operation and maintenance	241,242	227,232
Depreciation and amortization	97,303	100,061
Taxes, other than income	95,835	96,813
Total operating expenses	434,380	424,106
Operating income	369,652	380,172
Miscellaneous income	1,374	3,417
Interest charges	70,333	74,794
Income before income taxes	300,693	308,795
Income tax expense	115,356	121,029
Net income	$ 185,337	$ 187,766
Basic net income per share	$ 2.08	$ 2.20
Diluted net income per share	$ 2.06	$ 2.18
Cash dividends per share	$ 0.65	$ 0.64
Weighted average shares outstanding:		
Basic	89,133	85,404
Diluted	89,817	86,061

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2008	2007
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 185,337	$ 187,766
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	97,303	100,061
Charged to other accounts	67	118
Deferred income taxes	72,277	72,755
Other	6,853	9,472
Net assets / liabilities from risk management activities	38,165	50,540
Net change in operating assets and liabilities	79,190	91,215
Net cash provided by operating activities	479,192	511,927
Cash Flows From Investing Activities		
Capital expenditures	(198,722)	(172,792)
Other, net	(3,132)	(3,749)
Net cash used in investing activities	(201,854)	(176,541)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(150,582)	(382,416)
Repayment of long-term debt	(2,253)	(2,206)
Cash dividends paid	(58,431)	(54,640)
Issuance of common stock	12,839	12,428
Net proceeds from equity offering	—	191,913
Net cash used in financing activities	(198,427)	(234,921)
Net increase in cash and cash equivalents	78,911	100,465
Cash and cash equivalents at beginning of period	60,725	75,815
Cash and cash equivalents at end of period	$ 139,636	$ 176,280

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2008

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 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, 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 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 managed by 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 southeastern and midwestern states 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 derivative instruments.

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., each of which are wholly-owned by AEH. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, APS manages our natural gas gathering operations, which were limited in nature as of March 31, 2008. AES provides limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

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 its Annual Report on Form 10-K for the fiscal year ended September 30, 2007. Because of seasonal and other factors, the results of operations for the three and six-month periods ended March 31, 2008 are not indicative of our results of operations for the full 2008 fiscal year, which ends September 30, 2008.

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 year ended September 30, 2007. Except for the Company's adoption of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48), discussed below, there were no significant changes to those accounting policies during the six months ended March 31, 2008.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN 48 on October 1, 2007. As a result of adopting FIN 48, we determined that we had $6.1 million of liabilities associated with uncertain tax positions. Of this amount, $0.5 million was recognized as a result of adopting FIN 48 with an offsetting reduction to retained earnings.

Prior to October 1, 2007, the $5.6 million liability previously recorded for uncertain tax positions was reflected on the consolidated balance sheet as a component of deferred income taxes. As a result of adopting FIN 48, we recorded a $3.7 million liability as a component of other current liabilities and $2.4 million as a component of deferred credits and other liabilities, with offsetting decreases to the deferred income tax liability.

As of March 31, 2008, we had recorded liabilities associated with uncertain tax positions totaling $5.6 million. The realization of all of these tax benefits would reduce our income tax expense by approximately $5.6 million.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We did not recognize any material penalty and interest expenses during the six months ended March 31, 2008.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2001. The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns, and we anticipate these examinations will be completed by the end of fiscal 2008. We believe all material tax items which relate to the years under audit have been properly accrued.

Additionally, during the second quarter of fiscal 2008, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (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 March 31, 2008 and September 30, 2007 included the following:

	March 31, 2008	September 30, 2007
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 54,758	$ 59,022
Merger and integration costs, net	7,791	7,996
Deferred gas cost	41,113	14,797
Environmental costs	1,083	1,303
Rate case costs	12,538	10,989
Deferred franchise fees	721	796
Other	9,676	10,719
	$127,680	$105,622
Regulatory liabilities:		
Deferred gas cost	$ 27,388	$ 84,043
Regulatory cost of removal obligation	301,678	295,241
Deferred income taxes, net	165	165
Other	7,363	7,503
	$336,594	$386,952

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.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month and six-month periods ended March 31, 2008 and 2007:

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
	(In thousands)			
Net income	$111,534	$106,505	$185,337	$187,766
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(1,385) and $(134) for the three months ended March 31, 2008 and 2007 and of $(671) and $749 for the six months ended March 31, 2008 and 2007	(2,262)	(219)	(1,097)	1,222
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $482 and $982 for the three months ended March 31, 2008 and 2007 and $964 and $1,510 for the six months ended March 31, 2008 and 2007	787	1,602	1,574	2,462
Net unrealized gains on commodity hedging transactions, net of tax expense of $2,260 and $8,117 for the three months ended March 31, 2008 and 2007 and $7,197 and $15,336 for the six months ended March 31, 2008 and 2007	3,690	13,244	11,743	25,022
Comprehensive income	$113,749	$121,132	$197,557	$216,472

Accumulated other comprehensive loss, net of tax, as of March 31, 2008 and September 30, 2007 consisted of the following unrealized gains (losses):

	March 31, 2008	September 30, 2007
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 1,710	$ 2,807
Treasury lock agreements	(12,678)	(14,252)
Cash flow hedges	6,990	(4,753)
	$ (3,978)	$(16,198)

Recently issued accounting pronouncements

In March 2008, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133.* SFAS 161 expands the disclosure requirements for derivative instruments and for hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. The provisions of this standard will be effective for us beginning January 1, 2009. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued FASB Statement No. 141 (revised 2007), *Business Combinations*. SFAS 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS 141(R) significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under SFAS 141(R), changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. The provisions of this standard will apply to any acquisitions we may complete after October 1, 2009.

In December 2007, the FASB issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statement, an amendment of ARB No. 51*. SFAS 160 changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. The provisions of the standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at March 31, 2008 and September 30, 2007:

	Natural Gas Distribution	Natural Gas Marketing	Total
		(In thousands)	
March 31, 2008:			
Assets from risk management activities, current	$ 9,505	$ 4,951	$ 14,456
Assets from risk management activities, noncurrent	—	4,952	4,952
Liabilities from risk management activities, current	—	(31,908)	(31,908)
Liabilities from risk management activities, noncurrent	—	(970)	(970)
Net assets (liabilities)	$ 9,505	$(22,975)	$(13,470)
September 30, 2007:			
Assets from risk management activities, current	$ —	$ 21,849	$ 21,849
Assets from risk management activities, noncurrent	—	5,535	5,535
Liabilities from risk management activities, current	(21,053)	(286)	(21,339)
Liabilities from risk management activities, noncurrent	—	(290)	(290)
Net assets (liabilities)	$(21,053)	$ 26,808	$ 5,755

Natural Gas Distribution Hedging Activities

We use a combination of physical storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our natural gas distribution segment ultimately are recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, there is no impact on earnings from our natural gas distribution operations as a result of the use of financial derivatives.

Nonregulated Hedging Activities

AEH manages its exposure to the risk of natural gas price changes through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEH also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three and six-month periods ended March 31, 2008, the change in the deferred hedging position in accumulated other comprehensive loss primarily was attributable to increases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the six months ended March 31, 2008 of $2.1 million in net deferred hedging losses ($3.4 million in net deferred hedging gains being attributable to the three months ended March 31, 2008) in net income when the derivative contracts matured according to their terms. The net deferred hedging gain associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Most of the deferred hedging balance as of March 31, 2008 is expected to be recognized in net income in fiscal 2008 along with the corresponding hedged purchases and sales of natural gas.

Unrealized margins recorded in our income statement are comprised of various components, including, but not limited to, unrealized gains and losses arising from hedge ineffectiveness. Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative instrument and the hedged item and could materially affect our results of operations for the reported period. Although these unrealized gains and losses are currently recorded in our income statement, they are not indicative of the economic gross profit we anticipate to realize when the underlying physical and financial transactions are settled.

Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity are referred to as timing ineffectiveness. The portion of our unrealized margins related to basis and timing ineffectiveness gains and losses for the three and six months ended March 31, 2008 and 2007 are as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
	(In thousands)			
Basis ineffectiveness:				
Fair value basis ineffectiveness	$ (739)	$ 515	$ 1,217	$ (131)
Cash flow basis ineffectiveness	(634)	(893)	126	(769)
Total basis ineffectiveness	(1,373)	(378)	1,343	(900)
Timing ineffectiveness:				
Fair value timing ineffectiveness	6,965	19,570	43,618	80,302
Total hedge ineffectiveness	$ 5,592	$19,192	$44,961	$79,402

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no net 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. We may 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 March 31, 2008, AEH had a net open position (including existing storage) of 0.2 Bcf.

4. Debt

Long-term debt

Long-term debt at March 31, 2008 and September 30, 2007 consisted of the following:

	March 31, 2008	September 30, 2007
	(In thousands)	
Unsecured 4.00% Senior Notes, due October 2009	$ 400,000	$ 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 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 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
First Mortgage Bonds		
Series P, 10.43% due May 2008	6,250	7,500
Other term notes due in installments through 2013	2,887	3,890
Total long-term debt	2,131,440	2,133,693
Less:		
Original issue discount on unsecured senior notes and debentures	(3,291)	(3,547)
Current maturities	(8,453)	(3,831)
	$2,119,696	$2,126,315

Short-term debt

At March 31, 2008, there were no borrowings outstanding under our commercial paper program or bank credit facilities. At September 30, 2007, there was $150.6 million outstanding under our commercial paper program and bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of March 31, 2008, we had approximately $450 million of availability remaining under the registration statement. Due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until we received an investment grade rating from all of the three credit rating agencies.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of March 31, 2008, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility, expiring December 2011, for $600 million that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At March 31, 2008, there were no borrowings outstanding under our commercial paper program.

The second facility is a $300 million unsecured 364-day facility expiring November 2008, that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At March 31, 2008, there were no borrowings under this facility.

The third facility is an $18 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility expired on March 31, 2008 and was renewed effective April 1, 2008 for one year with no material changes to the terms and pricing. At March 31, 2008, there were no borrowings under this facility.

The availability of funds under our 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 our revolving credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2008, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt-to-total-capitalization ratio.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility. On March 31, 2008, AEM and the participating banks amended the facility, primarily to extend it to March 31, 2009. In addition, the amendment removed the financial covenant relating to the amount of cumulative losses that could be incurred by AEM and its subsidiaries over a specific period of time and included provisions permitting the participating banks, or their affiliates, to participate in physical commodity transactions with AEM.

Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR for the applicable interest period plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility not to exceed a maximum ratio of total liabilities to tangible net worth of 5 to 1. At March 31, 2008, AEM's ratio of total liabilities to tangible net worth, as defined, was 2.21 to 1. Additionally, AEM must maintain minimum levels of net working capital ranging from $20 million to $120 million and a minimum tangible net worth ranging from $21 million to $121 million. As defined in the financial covenants, at March 31, 2008, AEM's net working capital was $206.7 million and its tangible net worth was $214.9 million.

At March 31, 2008, there were no borrowings outstanding under this credit facility. However, at March 31, 2008, AEM letters of credit totaling $172.1 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 $27.9 million at March 31, 2008. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. In January 2008, the unused portion of this facility was terminated by the lending bank and the remaining balance will be terminated as the outstanding letters of credit expire. At March 31, 2008, there was $5.4 million in letters of credit outstanding under this facility.

The Company has a $200 million intercompany uncommitted revolving credit facility with AEH. This facility bears interest at the lesser of (i) the one-month LIBOR rate plus 0.20 percent or (ii) the marginal borrowing rate available to the Company on any such date under its commercial paper program. Applicable state regulatory commissions have approved this facility through December 31, 2008. At March 31, 2008, there was $16.1 million outstanding under this facility.

AEH has a $200 million intercompany uncommitted demand credit facility with the Company, which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.75 percent. Applicable state regulatory commissions have approved this facility through December 31, 2008. At March 31, 2008, there were no borrowings under this facility.

In addition, to supplement its $580 million credit facility, AEM has a $200 million intercompany uncommitted demand credit facility with AEH, which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility. At March 31, 2008, there were no borrowings under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9 million. At March 31, 2008 approximately $387.1 million of retained earnings was unrestricted with respect to the payment of dividends. In April 2008, we gave notice to the trustee and the holders of our intent to redeem our Series P First Mortgage Bonds which mature in November 2013. As the bonds will be redeemed in May 2008, the debt covenants described above will no longer apply.

We were in compliance with all of our debt covenants as of March 31, 2008. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. 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. In addition, 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. Additionally, this 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.

Except as described above, we have no 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.

5. Shareholders' Equity

Public Offering

On December 13, 2006, we completed a public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

Shareholder Rights Plan

In November 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998. Since that time, each share of common stock we have issued has included a right that entitles the holder to purchase from us a one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment. The description and terms of the rights are set forth in a rights agreement between us and the rights agent. The rights will terminate upon the expiration of the rights agreement on May 10, 2008.

6. Earnings Per Share

Basic and diluted earnings per share for the three and six months ended March 31, 2008 and 2007 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
	(In thousands, except per share amounts)			
Net income	$111,534	$106,505	$185,337	$187,766
Denominator for basic income per share — weighted average common shares	89,314	88,078	89,133	85,404
Effect of dilutive securities:				
Restricted and other shares	583	486	585	486
Stock options	93	171	99	171
Denominator for diluted income per share — weighted average common shares	89,990	88,735	89,817	86,061
Income per share — basic	$ 1.25	$ 1.21	$ 2.08	$ 2.20
Income per share — diluted	$ 1.24	$ 1.20	$ 2.06	$ 2.18

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2008 and 2007 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 six months ended March 31, 2008 and 2007 are presented in the following table. All 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 March 31			
	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,878	$ 4,018	$3,341	$2,807
Interest cost	6,736	6,495	2,912	2,641
Expected return on assets	(6,311)	(6,089)	(715)	(597)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(171)	45	—	8
Amortization of actuarial loss	1,926	2,434	—	—
Net periodic pension cost	$ 6,058	$ 6,903	$5,916	$5,237

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 7,756	$ 8,036	$ 6,682	$ 5,614
Interest cost	13,472	12,990	5,824	5,281
Expected return on assets	(12,621)	(12,178)	(1,430)	(1,194)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(342)	90	—	16
Amortization of actuarial loss	3,852	4,868	—	—
Net periodic pension cost	$ 12,117	$ 13,806	$11,832	$10,473

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2008 and 2007 are as follows:

	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
Discount rate	6.30%	6.30%	6.30%	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%	5.20%

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. However, we have made additional voluntary contributions to satisfy regulatory requirements in certain of our jurisdictions. During the six months ended March 31, 2008, we contributed $4.7 million to our other postretirement plans, and we expect to contribute a total of approximately $10 million to these plans during fiscal 2008.

8. Commitments and Contingencies

Litigation and Environmental Matters

The Company has continued to respond on a timely basis to data requests received from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation initiated in December 2007 into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. The data requests include requests for information and documents concerning specified short-term capacity release transportation transactions. We intend to fully cooperate with the Commission during its investigation. However, we currently are unable to predict the final outcome of this investigation or the potential impact it could have on our financial position, results of operations or cash flows.

The Texas Railroad Commission recently issued a directive and is currently developing a rulemaking concerning the replacement of compression couplings at pre-bent gas meter risers which could affect all natural gas utility companies operating in Texas. Compliance with the directive along with adoption of the pending rulemaking will require us to re-direct significant capital spending. These amounts should be recoverable through our rates.

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the year ended September 30, 2007, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2008. 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 March 31, 2008, AEM was committed to purchase 85.7 Bcf within one year, 31.7 Bcf within one to three years and 0.6 Bcf after three years under indexed contracts. AEM is committed to purchase 1.6 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $6.27 to $11.25. Purchases under these contracts totaled $860.3 million and $563.0 million for the three months ended March 31, 2008 and 2007 and $1,432.3 million and $983.4 for the six months ended March 31, 2008 and 2007.

Our natural gas distribution operations, other than the 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 its service area, which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of March 31, 2008 are as follows (in thousands):

2008	$134,763
2009	200,640
2010	125,092
2011	10,891
2012	10,774
Thereafter	14,380
	$496,540

Regulatory Matters

At March 31, 2008, we had rate cases in progress in our Georgia, Kansas, Mid-Tex and Virginia service areas. During the three months ended March 31, 2008, we reached settlement agreements with 438 of the 439 municipalities in our Mid-Tex Division, with the exception of the City of Dallas. The Railroad Commission of Texas heard arguments from the City of Dallas and Atmos Energy in late March and a final order is expected in June 2008. In our Kansas rate case, we reached a tentative settlement agreement with the Kansas Commission's Staff in March 2008. 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 15 to the financial statements in our Annual Report on Form 10-K for the year ended September 30, 2007. During the six months ended March 31, 2008, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage businesses as well as certain other nonregulated 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 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.

Our operations are divided into 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.

In our determination of reportable segments, we consider 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, 2007. We evaluate performance based on net income or loss of the respective operating units.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2007, we changed the composition of our operating segments. All prior period segment information has been restated to conform to our new segment presentation.

Income statements for the three and six-month periods ended March 31, 2008 and 2007 by segment are presented in the following tables:

	Three Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$1,521,636	$22,830	$ 931,990	$ 7,529	$ —	$2,483,985
Intersegment revenues	220	28,610	196,663	2,493	(227,986)	—
	1,521,856	51,440	1,128,653	10,022	(227,986)	2,483,985
Purchased gas cost	1,164,332	—	1,112,321	338	(227,400)	2,049,591
Gross profit	357,524	51,440	16,332	9,684	(586)	434,394
Operating expenses						
Operation and maintenance	98,578	15,086	5,525	1,536	(672)	120,053
Depreciation and amortization	43,130	4,907	374	379	—	48,790
Taxes, other than income	52,304	1,385	407	312	—	54,408
Total operating expenses	194,012	21,378	6,306	2,227	(672)	223,251
Operating income	163,512	30,062	10,026	7,457	86	211,143
Miscellaneous income	3,670	209	602	1,942	(4,956)	1,467
Interest charges	29,084	6,776	2,002	524	(4,870)	33,516
Income before income taxes	138,098	23,495	8,626	8,875	—	179,094
Income tax expense	52,442	8,271	3,347	3,500	—	67,560
Net income	$ 85,656	$15,224	$ 5,279	$ 5,375	$ —	$ 111,534
Capital expenditures	$ 89,671	$13,700	$ 38	$ 1,158	$ —	$ 104,567

	Three Months Ended March 31, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,460,861	$19,658	$583,269	$11,794	$ —	$2,075,582
Intersegment revenues	172	26,410	211,772	2,283	(240,637)	—
	1,461,033	46,068	795,041	14,077	(240,637)	2,075,582
Purchased gas cost	1,114,787	—	771,988	229	(240,108)	1,646,896
Gross profit	346,246	46,068	23,053	13,848	(529)	428,686
Operating expenses						
Operation and maintenance	92,328	12,353	6,590	1,206	(615)	111,862
Depreciation and amortization	45,904	4,324	448	390	—	51,066
Taxes, other than income	53,665	2,360	407	314	—	56,746
Total operating expenses	191,897	19,037	7,445	1,910	(615)	219,674
Operating income	154,349	27,031	15,608	11,938	86	209,012
Miscellaneous income	2,621	581	2,522	696	(4,582)	1,838
Interest charges	29,704	6,641	379	3,034	(4,496)	35,262
Income before income taxes	127,266	20,971	17,751	9,600	—	175,588
Income tax expense	50,946	7,698	6,720	3,719	—	69,083
Net income	$ 76,320	$13,273	$ 11,031	$ 5,881	$ —	$ 106,505
Capital expenditures	$ 71,278	$12,777	$ 312	$ 1,439	$ —	$ 85,806

	Six Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$2,449,665	$45,267	$1,634,712	$11,851	$ —	$4,141,495
Intersegment revenues	368	51,219	334,658	4,898	(391,143)	—
	2,450,033	96,486	1,969,370	16,749	(391,143)	4,141,495
Purchased gas cost	1,819,309	—	1,907,075	1,067	(389,988)	3,337,463
Gross profit	630,724	96,486	62,295	15,682	(1,155)	804,032
Operating expenses						
Operation and maintenance	195,825	30,518	13,402	2,824	(1,327)	241,242
Depreciation and amortization	85,962	9,823	761	757	—	97,303
Taxes, other than income	87,922	3,829	3,407	677	—	95,835
Total operating expenses	369,709	44,170	17,570	4,258	(1,327)	434,380
Operating income	261,015	52,316	44,725	11,424	172	369,652
Miscellaneous income	4,146	383	1,398	3,970	(8,523)	1,374
Interest charges	60,298	13,847	3,316	1,223	(8,351)	70,333
Income before income taxes	204,863	38,852	42,807	14,171	—	300,693
Income tax expense	79,043	13,781	16,928	5,604	—	115,356
Net income	$ 125,820	$25,071	$ 25,879	$ 8,567	$ —	$ 185,337
Capital expenditures	$ 173,984	$22,082	$ 69	$ 2,587	$ —	$ 198,722

	Six Months Ended March 31, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,424,944	$38,335	$1,194,638	$20,298	$ —	$3,678,215
Intersegment revenues	333	47,605	312,097	5,112	(365,147)	—
	2,425,277	85,940	1,506,735	25,410	(365,147)	3,678,215
Purchased gas cost	1,816,463	—	1,420,548	454	(363,528)	2,873,937
Gross profit	608,814	85,940	86,187	24,956	(1,619)	804,278
Operating expenses						
Operation and maintenance	190,441	23,455	12,168	2,959	(1,791)	227,232
Depreciation and amortization	89,626	8,841	777	817	—	100,061
Taxes, other than income	91,287	4,296	656	574	—	96,813
Total operating expenses	371,354	36,592	13,601	4,350	(1,791)	424,106
Operating income	237,460	49,348	72,586	20,606	172	380,172
Miscellaneous income	4,401	910	4,238	1,596	(7,728)	3,417
Interest charges	62,177	14,132	1,406	4,635	(7,556)	74,794
Income before income taxes	179,684	36,126	75,418	17,567	—	308,795
Income tax expense	71,530	13,202	29,440	6,857	—	121,029
Net income	$ 108,154	$22,924	$ 45,978	$10,710	$ —	$ 187,766
Capital expenditures	$ 143,697	$26,381	$ 650	$ 2,064	$ —	$ 172,792

Balance sheet information at March 31, 2008 and September 30, 2007 by segment is presented in the following tables:

	March 31, 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	$3,350,194	$542,913	$ 7,579	$ 48,180	$ —	$3,948,866
Investment in subsidiaries	467,734	—	(2,096)	—	(465,638)	—
Current assets						
Cash and cash equivalents	48,027	—	56,760	34,849	—	139,636
Cash held on deposit in margin account	—	—	29,591	—	—	29,591
Assets from risk management activities	9,505	—	8,416	143	(3,608)	14,456
Other current assets	730,288	16,733	598,872	31,476	(68,338)	1,309,031
Intercompany receivables	499,300	—	—	182,483	(681,783)	—
Total current assets	1,287,120	16,733	693,639	248,951	(753,729)	1,492,714
Intangible assets	—	—	2,404	—	—	2,404
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	4,952	—	—	4,952
Deferred charges and other assets	211,199	7,660	1,253	16,970	—	237,082
	$5,884,022	$699,796	$732,013	$324,530	$(1,219,367)	$6,420,994
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,125,993	$113,789	$153,582	$200,363	$ (467,734)	$2,125,993
Long-term debt	2,119,012	—	—	684	—	2,119,696
Total capitalization	4,245,005	113,789	153,582	201,047	(467,734)	4,245,689
Current liabilities						
Current maturities of long-term debt	6,250	—	—	2,203	—	8,453
Short-term debt	16,100	—	—	—	(16,100)	—
Liabilities from risk management activities	—	—	32,046	3,470	(3,608)	31,908
Other current liabilities	729,350	3,335	396,087	107,177	(50,142)	1,185,807
Intercompany payables	—	536,863	144,920	—	(681,783)	—
Total current liabilities	751,700	540,198	573,053	112,850	(751,633)	1,226,168
Deferred income taxes	367,415	42,134	3,700	6,983	—	420,232
Noncurrent liabilities from risk management activities	—	—	970	—	—	970
Regulatory cost of removal obligation	277,560	—	—	—	—	277,560
Deferred credits and other liabilities	242,342	3,675	708	3,650	—	250,375
	$5,884,022	$699,796	$732,013	$324,530	$(1,219,367)	$6,420,994

	September 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,251,144	$531,921	$ 7,850	$ 45,921	$ —	$3,836,836
Investment in subsidiaries	396,474	—	(2,096)	—	(394,378)	—
Current assets						
Cash and cash equivalents	28,881	—	31,703	141	—	60,725
Cash held on deposit in margin account	—	—	—	—	—	—
Assets from risk management activities	—	—	26,783	12,947	(17,881)	21,849
Other current assets	643,353	20,065	337,169	76,731	(90,997)	986,321
Intercompany receivables	536,985	—	—	114,300	(651,285)	—
Total current assets	1,209,219	20,065	395,655	204,119	(760,163)	1,068,895
Intangible assets	—	—	2,716	—	—	2,716
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	5,535	—	—	5,535
Deferred charges and other assets	227,869	4,898	1,279	13,913	—	247,959
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,965,754	$ 88,719	$107,090	$200,665	$ (396,474)	$1,965,754
Long-term debt	2,125,007	—	—	1,308	—	2,126,315
Total capitalization	4,090,761	88,719	107,090	201,973	(396,474)	4,092,069
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,581	—	3,831
Short-term debt	187,284	—	30,000	—	(66,685)	150,599
Liabilities from risk management activities	21,053	—	18,167	—	(17,881)	21,339
Other current liabilities	519,642	6,394	186,792	53,297	(22,216)	743,909
Intercompany payables	—	550,184	101,101	—	(651,285)	—
Total current liabilities	729,229	556,578	336,060	55,878	(758,067)	919,678
Deferred income taxes	326,518	40,565	(8,925)	12,411	—	370,569
Noncurrent liabilities from risk management activities	—	—	290	—	—	290
Regulatory cost of removal obligation	271,059	—	—	—	—	271,059
Deferred credits and other liabilities	234,914	3,512	706	4,120	—	243,252
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of March 31, 2008, and the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2008 and 2007, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2008 and 2007. 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, 2007, 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 27, 2007, 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, 2007, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
May 5, 2008

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, 2007.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar 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 year ended September 30, 2007, include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in one state; adverse weather conditions; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; the capital-intensive nature of our distribution business, increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the impact of environmental regulations on our business; the inherent hazards and risks involved in operating our distribution business, natural disasters, terrorist activities or other events; and other uncertainties, which may be discussed herein, including the outcome of any pending federal or state regulatory investigations, 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 Corporation 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.

Our operations are divided into 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, 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 year ended September 30, 2007 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 by the Audit Committee quarterly. There were no significant changes to these critical accounting policies during the six months ended March 31, 2008.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2008 and 2007:

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
	(In thousands)			
Operating revenues	$2,483,985	$2,075,582	$4,141,495	$3,678,215
Gross profit	434,394	428,686	804,032	804,278
Operating expenses	223,251	219,674	434,380	424,106
Operating income	211,143	209,012	369,652	380,172
Miscellaneous income	1,467	1,838	1,374	3,417
Interest charges	33,516	35,262	70,333	74,794
Income before income taxes	179,094	175,588	300,693	308,795
Income tax expense	67,560	69,083	115,356	121,029
Net income	$ 111,534	$ 106,505	$ 185,337	$ 187,766
Diluted net income per share	$ 1.24	$ 1.20	$ 2.06	$ 2.18

Our consolidated net income during the three and six months ended March 31, 2008 and 2007 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands)		
Natural gas distribution segment	$ 85,656	$ 76,320	$ 9,336
Regulated transmission and storage segment	15,224	13,273	1,951
Natural gas marketing segment	5,279	11,031	(5,752)
Pipeline, storage and other segment	5,375	5,881	(506)
Net income	$111,534	$106,505	$ 5,029

	Six Months Ended March 31		
	2008	2007	Change
	(In thousands)		
Natural gas distribution segment	$125,820	$108,154	$ 17,666
Regulated transmission and storage segment	25,071	22,924	2,147
Natural gas marketing segment	25,879	45,978	(20,099)
Pipeline, storage and other segment	8,567	10,710	(2,143)
Net income	$185,337	$187,766	$ (2,429)

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

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands, except per share data)		
Regulated operations	$100,880	$ 89,593	$11,287
Nonregulated operations	10,654	16,912	(6,258)
Consolidated net income	$111,534	$106,505	$ 5,029
Diluted EPS from regulated operations	$ 1.12	$ 1.01	$ 0.11
Diluted EPS from nonregulated operations	0.12	0.19	(0.07)
Consolidated diluted EPS	$ 1.24	$ 1.20	$ 0.04

	Six Months Ended March 31		
	2008	2007	Change
	(In thousands, except per share data)		
Regulated operations	$150,891	$131,078	$ 19,813
Nonregulated operations	34,446	56,688	(22,242)
Consolidated net income	$185,337	$187,766	$ (2,429)
Diluted EPS from regulated operations	$ 1.68	$ 1.52	$ 0.16
Diluted EPS from nonregulated operations	0.38	0.66	(0.28)
Consolidated diluted EPS	$ 2.06	$ 2.18	$ (0.12)

The following summarizes the results of our operations and other significant events for the six months ended March 31, 2008:

- Regulated operations generated 81 percent of net income during the six months ended March 31, 2008 compared to 70 percent during the six months ended March 31, 2007. The $19.8 million increase in our regulated operations net income primarily reflects rate increases in our Mid-Tex, Kentucky, Louisiana and Tennessee service areas coupled with higher rates and throughput in our Atmos Pipeline — Texas Division.

- Nonregulated operations contributed 19 percent of net income during the six months ended March 31, 2008 compared to 30 percent during the six months ended March 31, 2007. The $22.2 million decrease in our nonregulated operations net income primarily reflects lower asset optimization margins partially offset by higher delivered gas margins and lower unrealized losses.

- For the six months ended March 31, 2008, we generated $479.2 million in operating cash flow compared with $511.9 million for the six months ended March 31, 2007, primarily reflecting an increase in cash required to collateralize our risk management accounts.

- In September 2007, we filed a statement of intent for a rate increase of $51.9 million in our Mid-Tex Division. During the three months ended March 31, 2008, we reached settlement agreements with 438 of the 439 cities in our Mid-Tex Division. The only city that has not settled is the City of Dallas. In March 2008, hearings were conducted at the Railroad Commission of Texas on the rate case with the City of Dallas, with a final order expected in June 2008.

Three Months Ended March 31, 2008 compared with Three Months Ended March 31, 2007

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. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

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.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2008 and 2007 are presented below.

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	$357,524	$346,246	$11,278
Operating expenses	194,012	191,897	2,115
Operating income	163,512	154,349	9,163
Miscellaneous income	3,670	2,621	1,049
Interest charges	29,084	29,704	(620)
Income before income taxes	138,098	127,266	10,832
Income tax expense	52,442	50,946	1,496
Net income	$ 85,656	$ 76,320	$ 9,336
Consolidated natural gas distribution sales volumes — MMcf	135,568	133,856	1,712
Consolidated natural gas distribution transportation volumes — MMcf	39,730	39,567	163
Total consolidated natural gas distribution throughput — MMcf	175,298	173,423	1,875
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.44	$ 0.48	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 8.59	$ 8.33	$ 0.26

The following table shows our operating income by natural gas distribution division for the three months ended March 31, 2008 and 2007. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands)		
Colorado-Kansas	$ 15,536	$ 14,968	$ 568
Kentucky/Mid-States	29,875	28,948	927
Louisiana	19,236	23,026	(3,790)
Mid-Tex	72,479	59,007	13,472
Mississippi	16,514	16,204	310
West Texas	8,919	12,115	(3,196)
Other	953	81	872
Total	$163,512	$154,349	$ 9,163

The $11.3 million increase in natural gas distribution gross profit primarily reflects a $13.4 million net increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division, which increased $12.4 million as a result of the 2006 Gas Reliability Infrastructure Program (GRIP) filing, the prior Mid-Tex rate case, which was substantially concluded in March 2007 and the absence of a one-time GRIP refund in the prior year. The current-year period also reflects $3.8 million in rate increases in our Kentucky, Louisiana, Tennessee and West Texas service areas.

Gross profit also increased approximately $4.0 million in revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This increase, partially offset by a $1.3 million quarter-over-quarter increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $2.7 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 and taxes, other than income, increased $2.1 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $7.9 million, primarily due to an overall increase in administrative costs. The prior-year quarter includes the favorable impact of a nonrecurring $4.3 million deferral of incremental Hurricane Katrina-related operation and maintenance expenses in the prior-year quarter.

The provision for doubtful accounts decreased $1.6 million to $2.8 million for the three months ended March 31, 2008. The decrease primarily was attributable to stronger collection efforts.

Depreciation and amortization expense decreased $2.8 million for the second quarter of fiscal 2008 compared with second quarter of fiscal 2007. The decrease primarily was attributable to changes in depreciation rates as a result of recent rate cases.

Results for the quarter include 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 decreased $0.6 million due to lower average effective interest rates experienced during the current-year quarter compared to the prior-year quarter.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 2008 are discussed below. The amounts described below represent the gross revenues that were requested or received in each rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Mid-Tex Division Rate Settlements

In September 2007, Atmos Energy filed a statement of intent for a rate increase of $51.9 million in our Mid-Tex Division. During the fiscal 2008 second quarter, we reached settlement agreements with 438 of the 439 cities, and have support from Railroad Commission of Texas staff to implement the settlement for our environs customers. The City of Dallas is the only city with whom we have not reached a settlement. The settlement agreement includes i) an increase of approximately $10 million, that was implemented effective April 1, 2008; ii) a rate review mechanism (RRM) that will reflect annual changes in the Mid-Tex Division's cost of service and rate base; iii) an authorized return on equity of 9.6 percent; and iv) the establishment of a new program designed to encourage natural gas conservation.

In March 2008, hearings were conducted at the Railroad Commission of Texas (RRC) on the rate case with the City of Dallas. We expect to receive a proposal for decision in mid-May 2008 with a final order expected in June 2008.

In April 2008, the Mid-Tex Division filed its first Rate Review Mechanism that will adjust rates, effective October 1, 2008, for the cities that have agreed to the settlement. The proposed increase to base rates is $33.5 million.

Other Rate Case Filings

In May 2006, Atmos Energy began receiving "show cause" ordinances from several of the cities in the West Texas Division. In December 2007, our West Texas Division reached a settlement agreement with the West Texas cities resulting in an approved GRIP filing to include in rate base approximately $7.0 million of capital costs incurred during calendar year 2006. The filing should result in additional annual revenues of approximately $1.1 million. The settlement agreement also included an agreement to work on a rate review mechanism for our West Texas system during 2008 which, like the Mid-Tex Division's RRM, would adjust rates on a periodic basis to reflect changes in the West Texas Division's cost of service and rate base for this service area.

In October 2007, our Kentucky/Mid-States Division settled its $11.1 million rate case filed in May 2007 with the Tennessee Regulatory Authority. The settlement resulted in an increase in annual revenue of $4.0 million and a $4.1 million reduction in depreciation expense.

In September 2007, we filed an application with the Kansas Corporation Commission (KCC) requesting a rate increase of $5.0 million in our Kansas service area. A tentative settlement for an increase in annual revenue of $2.1 million was reached with the Kansas Commission Staff in March 2008. The settlement was contested by the Consumer Utility Ratepayer Board. A hearing on the merits of the settlement was conducted in April 2008 and a final order is expected in May 2008.

In February 2008, we filed for a rate increase of $0.9 million in the Virginia jurisdiction of our Kentucky/ Mid-States Division. A procedural schedule has been established that should result in a final order being issued by the fourth quarter of fiscal year 2008.

In March 2008, we filed for a rate increase of $6.2 million in the Georgia jurisdiction of our Kentucky/ Mid-States Division. A procedural schedule has been established that should result in a final order being issued by the fourth quarter of fiscal year 2008.

Stable Rate Filings

Louisiana Division. In December 2007, we filed our TransLa annual rate stabilization clause with the Louisiana Public Service Commission requesting an increase of $2.2 million, including an increase in depreciation expense of approximately $0.4 million. The filing was for the test year ended September 30, 2007. The TransLa filing was approved in March 2008 and resulted in an increase of $2.1 million in annual revenue effective April 1, 2008. In April 2008, we filed the LGS annual rate stabilization clause, requesting an increase of $2.6 million. The filing was for the test year ended December 31, 2007 and is expected to be effective July 1, 2008.

Mississippi Division. In December 2007, the Mississippi Public Service Commission approved our annual stable rate filing with no change in rates.

Regulated Transmission and Storage Segment

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

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2008 and 2007 are presented below.

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 28,260	$ 25,967	$ 2,293
Third-party transportation	18,229	13,702	4,527
Storage and park and lend services	1,862	1,876	(14)
Other	3,089	4,523	(1,434)
Gross profit	51,440	46,068	5,372
Operating expenses	21,378	19,037	2,341
Operating income	30,062	27,031	3,031
Miscellaneous income	209	581	(372)
Interest charges	6,776	6,641	135
Income before income taxes	23,495	20,971	2,524
Income tax expense	8,271	7,698	573
Net income	$ 15,224	$ 13,273	$ 1,951
Gross pipeline transportation volumes — MMcf	223,476	199,701	23,775
Consolidated pipeline transportation volumes — MMcf	141,108	116,995	24,113

The $5.4 million increase in gross profit primarily was attributable to a $3.0 million increase from rate adjustments resulting from our 2006 GRIP filing and a $1.7 million increase from transportation volumes. Consolidated throughput increased 21 percent, primarily due to increased transportation in the Barnett Shale and Carthage regions of Texas. The improvement in gross profit also reflects increased service fees and unit transportation margins due to favorable market conditions which contributed $1.7 million. These increases were partially offset by a $1.5 million decrease in sales of excess gas that occurred in the prior-year quarter.

Operating expenses increased $2.3 million primarily due to increased pipeline integrity and maintenance costs.

Recent Ratemaking Developments

In April 2008, the RRC approved the GRIP filing for our Atmos Pipeline — Texas Division to include in rate base approximately $46.6 million of capital costs incurred during calendar year 2007. The filing should result in additional annual revenues of approximately $7.0 million. These revenues represent the gross revenues that were received in the filing, which may not necessarily result in an equal increase in operating income, as some operating costs may increase.

Natural Gas Marketing Segment

Our natural gas marketing segment 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 derivative products. 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.

To optimize the storage and transportation capacity we own or control, we 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. Additionally, we engage 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 contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Atmos Energy Marketing, LLC (AEM) continually manages its net physical position to enhance the future economic profit it captured when an original transaction was executed. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective.

We use derivatives, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These derivatives 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 the unrealized margins reported as a part of our storage activities until the underlying physical gas is cycled and the related financial derivatives are settled.

AEM also uses derivative instruments to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original physical inventory hedge and to insulate and protect the economic value within its storage and marketing activities. Changes in fair value associated with these financial instruments are recognized as unrealized gains and losses within AEM's storage and marketing activities 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 March 31, 2008 and 2007 are presented below. Gross profit margin for our natural gas marketing segment consists primarily of margins earned from the delivery of gas and related services requested by our customers and asset optimization activities which are derived from the utilization of our managed proprietary and 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 net physical gas position and related derivative contracts used by our natural gas marketing segment to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical 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 unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended March 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Delivered gas	$ 26,195	$ 14,252	$ 11,943
Asset optimization	27,737	77,724	(49,987)
Unrealized margins	(37,600)	(68,923)	31,323
Gross profit	16,332	23,053	(6,721)
Operating expenses	6,306	7,445	(1,139)
Operating income	10,026	15,608	(5,582)
Miscellaneous income	602	2,522	(1,920)
Interest charges	2,002	379	1,623
Income before income taxes	8,626	17,751	(9,125)
Income tax expense	3,347	6,720	(3,373)
Net income	$ 5,279	$ 11,031	$ (5,752)
Gross natural gas marketing sales volumes — MMcf	136,677	114,110	22,567
Consolidated natural gas marketing sales volumes — MMcf	120,023	101,386	18,637
Net physical position (Bcf)	20.7	19.6	1.1

The $6.7 million decrease in our natural gas marketing segment's gross profit primarily reflects a $50.0 million decrease in asset optimization margins. Natural gas market conditions were significantly less volatile during the current-year quarter compared with the prior-year quarter, which created fewer opportunities to capitalize on price fluctuations. As a result, the decrease in asset optimization is primarily attributable to smaller gains realized from the settlement of financial positions related to physical gas deliveries from our storage assets compared with the prior-year quarter. Additionally, increased storage demand fees incurred to support our asset optimization activities contributed to the decrease in gross profit.

An $11.9 million increase in delivered gas margins partially offset the decrease in asset optimization activities resulting from increased sales volumes and increased per unit margins. Gross sales volumes increased 20 percent compared with the prior-year quarter as a result of the successful execution of our marketing efforts. The increase in delivered gas margin was also attributable to the realization of favorable gains due to the location of gas sold. After excluding the effect of these location basis gains, we experienced a 24 percent increase in per-unit margins during the three months ended March 31, 2008 compared with the prior-year quarter.

Gross profit margin was also favorably impacted by a $31.3 million increase in unrealized margins attributable to a narrowing of the spreads between the current cash prices and forward natural gas prices during the current-year quarter compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, decreased $1.1 million primarily due to a decrease in employee and other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented to provide a measure of the potential gross profit from asset optimization that could occur in future periods if AEM's optimization efforts are executed as planned. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents AEM's economic gross profit and its potential gross profit at March 31, 2008, December 31, 2007 and September 30, 2007.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gain (Loss)	Potential Gross Profit
	(Bcf)	(In millions)	(In millions)	(In millions)
March 31, 2008	20.7	$10.8	$ (0.6)	$11.4
December 31, 2007	17.7	$44.2	$32.9	$11.3
September 30, 2007	12.3	$40.8	$10.8	$30.0

As of March 31, 2008, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $10.8 million. This amount is increased by $0.6 million of net unrealized losses recorded in the financial statements as of March 31, 2008 that will reverse when the inventory is withdrawn and the accompanying financial derivatives are settled. Therefore, the potential gross profit was $11.4 million. This potential gross profit amount will likely not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses and increased income taxes to realize this amount.

The $0.1 million increase in potential gross profit as compared to December 31, 2007, reflects a $33.5 million decrease in unrealized gains primarily attributable to realizing previously recorded gains offset by a $33.4 million decrease in the economic gross profit. As a result of the natural gas market conditions experienced during the quarter, AEM elected to recognize most of the economic value captured as of December 31, 2007 by cycling gas from storage and executing the associated financial contracts. During this process, AEM increased its net physical position; however, the captured spreads were lower than in prior periods.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled 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 March 31, 2008 will be fully realized in the future nor can we predict in what time periods such realization will 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 March 31, 2008, without encountering operational or other issues, we anticipate a portion of the potential gross profit as of March 31, 2008 will be recognized during the remainder of fiscal 2008 with most of the remainder recognized during fiscal 2009.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by Atmos Energy Holdings, Inc.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of March 31, 2008, these activities were limited in nature.

AES, through December 31, 2006, provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our natural gas distribution service areas at competitive prices. Effective January 1, 2007, these activities were moved to our shared services function included in our natural gas distribution segment. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Results for this segment are primarily impacted 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 March 31, 2008 and 2007 are presented below.

	Three Months Ended March 31		
	2008	2007	Change
		(In thousands)	
Storage and transportation services	$ 4,317	$ 3,726	$ 591
Asset optimization	6,070	13,729	(7,659)
Other	1,225	788	437
Unrealized margins	(1,928)	(4,395)	2,467
Gross profit	9,684	13,848	(4,164)
Operating expenses	2,227	1,910	317
Operating income	7,457	11,938	(4,481)
Miscellaneous income	1,942	696	1,246
Interest charges	524	3,034	(2,510)
Income before income taxes	8,875	9,600	(725)
Income tax expense	3,500	3,719	(219)
Net income	$ 5,375	$ 5,881	$ (506)

Pipeline, storage and other gross profit decreased $4.2 million primarily due to a $7.7 million decrease in asset optimization margins as a result of a less volatile natural gas market. This decrease was partially offset by a $2.5 million increase in unrealized margins associated with asset optimization activities.

Operating expenses increased $0.3 million primarily due to an increase in employee and other administrative costs.

Six Months Ended March 31, 2008 compared with Six Months Ended March 31, 2007

Natural Gas Distribution Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2008 and 2007 are presented below.

	Six Months Ended March 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Gross profit	$630,724	$608,814	$21,910
Operating expenses	369,709	371,354	(1,645)
Operating income	261,015	237,460	23,555
Miscellaneous income	4,146	4,401	(255)
Interest charges	60,298	62,177	(1,879)
Income before income taxes	204,863	179,684	25,179
Income tax expense	79,043	71,530	7,513
Net income	$125,820	$108,154	$17,666
Consolidated natural gas distribution sales volumes — MMcf	220,335	220,256	79
Consolidated natural gas distribution transportation volumes — MMcf	73,479	72,261	1,218
Total consolidated natural gas distribution throughput — MMcf	293,814	292,517	1,297
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.44	$ 0.48	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 8.26	$ 8.25	$ 0.01

The following table shows our operating income by natural gas distribution division for the six months ended March 31, 2008 and 2007. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2008	2007	Change
	(In thousands)		
Colorado-Kansas	$ 22,224	$ 23,640	$(1,416)
Kentucky/Mid-States	44,043	43,151	892
Louisiana	31,168	33,619	(2,451)
Mid-Tex	122,704	94,347	28,357
Mississippi	24,343	23,803	540
West Texas	13,895	18,621	(4,726)
Other	2,638	279	2,359
Total	$261,015	$237,460	$23,555

The $21.9 million increase in natural gas distribution gross profit primarily reflects a $22.8 million net increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division which increased $19.1 million as a result of the 2006 GRIP filing, the previous Mid-Tex rate case, which was substantially concluded in March 2007 and the absence of a one time GRIP refund in the prior year. The current-year period also reflects $7.2 million in rate increases in our Kentucky, Louisiana, Tennessee and West Texas service areas.

Gross profit also increased approximately $6.0 million in revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current-year period compared to the prior-year period. This increase, coupled with a $0.4 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 $6.4 million increase 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 and taxes, other than income, decreased by $1.6 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $8.8 million, primarily due to increased administrative and natural gas odorization costs partially offset by lower employee costs. The increase in operation and maintenance expense also reflects the absence in the current-year period of the aforementioned nonrecurring $4.3 million deferral of hurricane-related operation and maintenance expenses.

The provision for doubtful accounts decreased $3.4 million to $7.4 million for the six months ended March 31, 2008. The decrease primarily was attributable to stronger collection efforts.

Depreciation and amortization expense decreased $3.7 million for the six months ended March 31, 2008 compared with the six months ended March 31, 2007. The decrease primarily was attributable to changes in depreciation rates as a result of recent rate cases.

Results for the current-year period include 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 decreased $1.9 million due to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period.

Regulated Transmission and Storage Segment

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2008 and 2007 are presented below.

	Six Months Ended March 31		
	2008	2007	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 50,648	$ 46,431	$ 4,217
Third-party transportation	36,461	28,355	8,106
Storage and park and lend services	3,901	5,050	(1,149)
Other	5,476	6,104	(628)
Gross profit	96,486	85,940	10,546
Operating expenses	44,170	36,592	7,578
Operating income	52,316	49,348	2,968
Miscellaneous income	383	910	(527)
Interest charges	13,847	14,132	(285)
Income before income taxes	38,852	36,126	2,726
Income tax expense	13,781	13,202	579
Net income	$ 25,071	$ 22,924	$ 2,147
Gross pipeline transportation volumes — MMcf	412,340	370,319	42,021
Consolidated pipeline transportation volumes — MMcf	277,308	233,808	43,500

The $10.5 million increase in gross profit primarily was attributable to a $5.7 million increase from rate adjustments resulting from our 2006 GRIP filing and a $3.7 million increase from transportation volumes. Consolidated throughput increased 19 percent primarily due to increased transportation in the Barnett Shale and Carthage regions of Texas. The improvement in gross profit also reflects increased service fees and unit transportation margins due to favorable market conditions which contributed $2.1 million. New compression contracts and transportation capacity enhancements also contributed $1.6 million. These increases were partially offset by a $1.5 million decrease in sales of excess gas compared to the same period in the prior year and a $1.2 million decrease in storage, parking and lending services due to market conditions.

Operating expenses increased $7.6 million primarily due to increased pipeline integrity and maintenance costs.

Natural Gas Marketing Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2008 and 2007 are presented below.

	Six Months Ended March 31		
	2008	**2007**	**Change**
	(In thousands, unless otherwise noted)		
Delivered gas	$ 44,368	$ 34,321	$ 10,047
Asset optimization	27,212	71,934	(44,722)
Unrealized margins	(9,285)	(20,068)	10,783
Gross profit	62,295	86,187	(23,892)
Operating expenses	17,570	13,601	3,969
Operating income	44,725	72,586	(27,861)
Miscellaneous income	1,398	4,238	(2,840)
Interest charges	3,316	1,406	1,910
Income before income taxes	42,807	75,418	(32,611)
Income tax expense	16,928	29,440	(12,512)
Net income	$ 25,879	$ 45,978	$(20,099)
Gross natural gas marketing sales volumes — MMcf	245,386	202,148	43,238
Consolidated natural gas marketing sales volumes — MMcf	216,229	178,912	37,317
Net physical position (Bcf)	20.7	19.6	1.1

The $23.9 million decrease in our natural gas marketing segment's gross profit primarily reflects a $44.7 million decrease in asset optimization margins. As a result of the less volatile natural gas market, we recognized smaller gains on the settlement of financial positions related to physical gas deliveries from storage assets. Additionally, increased storage fees charged by third parties contributed to the decrease in asset optimization gross profit.

The decrease was partially offset by a $10.0 million increase in delivered gas margins. Gross sales volumes increased 21 percent compared with the prior-year period. The increase in delivered gas margin was also attributable to the realization of favorable gains due to the location of gas sold in certain market areas on certain contracts. After excluding the effect of these location basis gains, we experienced an 11 percent decrease in per-unit margins during the six months ended March 31, 2008, compared with the prior-year period as the increases experienced during the second quarter partially offset the decreases experienced during the first quarter of fiscal 2008.

Gross profit margin was also favorably impacted by a $10.8 million increase in unrealized margins attributable to a narrowing of the spreads between the current cash prices and forward natural gas prices during the current-year period compared with the prior-year period.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $4.0 million. The increase reflects $2.4 million for the settlement of certain tax matters coupled with a $1.6 million increase in employee and other administrative costs.

Pipeline, Storage and Other Segment

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the six months ended March 31, 2008 and 2007 are presented below.

	Six Months Ended March 31		
	2008	2007	Change
		(In thousands)	
Storage and transportation services	$ 7,634	$ 7,790	$ (156)
Asset optimization	5,112	13,194	(8,082)
Other	2,491	2,147	344
Unrealized margins	445	1,825	(1,380)
Gross profit	15,682	24,956	(9,274)
Operating expenses	4,258	4,350	(92)
Operating income	11,424	20,606	(9,182)
Miscellaneous income	3,970	1,596	2,374
Interest charges	1,223	4,635	(3,412)
Income before income taxes	14,171	17,567	(3,396)
Income tax expense	5,604	6,857	(1,253)
Net income	$ 8,567	$10,710	$(2,143)

Pipeline, storage and other gross profit decreased $9.3 million primarily due to an $8.1 million decrease in asset optimization margins as a result of a less volatile natural gas market. The change in gross profit also reflects a decrease of $1.4 million in unrealized margins associated with asset optimization activities.

Operating expenses for the six months ended March 31, 2008 remained generally unchanged compared with the prior-year period.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

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, 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 six months ended March 31, 2008, we generated operating cash flow of $479.2 million from operating activities compared with $511.9 million for the six months ended March 31, 2007. Period over period, our operating cash flow was reduced primarily by cash required to collateralize our risk management accounts, which reduced operating cash flows by $24.5 million. Changes in accounts receivable and other current assets reduced operating cash flow by $103.7 million. These decreases were partially offset by favorable timing of accounts payable and accrued liabilities which increased operating cash flow by $133.8 million. Finally, other changes in working capital and other items decreased operating cash flow by $38.3 million, primarily resulting from unfavorable net changes associated with our risk management activities.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund acquisitions and growth projects, our ongoing construction program and improvements to information 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, 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 2008 are expected to range from $450 million to $465 million. For the six months ended March 31, 2008, we incurred $198.7 million for capital expenditures compared with $172.8 million for the six months ended March 31, 2007. The increase in capital spending primarily reflects an increase in main replacements in our Mid- Tex Division and spending in the natural gas distribution segment for our new automated metering initiative. This initiative involves the installation of equipment that automatically reads and transfers customer consumption and other data to our customer information systems. This initiative is expected to improve the efficiency of our meter reading process.

Cash flows from financing activities

For the six months ended March 31, 2008, our financing activities reflected a use of cash of $198.4 million compared with $234.9 million in the prior-year period. Our significant financing activities for the six months ended March 31, 2008 and 2007 are summarized as follows.

- During the six months ended March 31, 2008, we repaid all amounts outstanding under our credit facilities, which represented a $150.6 million use of cash. The repayment reflects the positive impact of our strong operating cash flow during 2008.
- In December 2006, we sold 6.3 million shares of common stock in an offering, including the underwriters' exercise of their overallotment option of 0.8 million shares, generating net proceeds of approximately $192 million. The net proceeds from this issuance were used to reduce our short-term debt.
- During the six months ended March 31, 2008, we paid $58.4 million in cash dividends compared with $54.6 million for the six months ended March 31, 2007. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.64 per share during the six months ended March 31, 2007 to $0.65 per share during the six months ended March 31, 2008 combined with our December 2006 equity offering and new share issuances under our various equity plans.

- During the six months ended March 31, 2008, we issued 0.5 million shares of common stock under our various equity plans which generated net proceeds of $12.8 million. In addition, we granted 0.3 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the six months ended March 31, 2008 and 2007.

	Six Months Ended March 31	
	2008	2007
Shares issued:		
Direct Stock Purchase Plan	203,025	158,416
Retirement Savings Plan	268,712	191,617
1998 Long-Term Incentive Plan	343,500	348,642
Outside Directors Stock-for-Fee Plan	1,602	1,162
Public Offering	—	6,325,000
Total shares issued	816,839	7,024,837

Credit Facilities

As of March 31, 2008, we had a total of approximately $1.5 billion of credit facilities, comprised of three short-term committed credit facilities totaling $918 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

As of March 31, 2008, the amount available to us under our credit facilities, net of outstanding letters of credit, was $945.9 million. We believe these credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of March 31, 2008, we had approximately $450 million available for issuance under the registration statement. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

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). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P maintains its positive outlook while Moody's and Fitch maintain their stable outlook. None of our ratings are currently under review.

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 March 31, 2008. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization as of March 31, 2008, September 30, 2007 and March 31, 2007:

	March 31, 2008		September 30, 2007		March 31, 2007	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 150,599	3.5%	$ —	—%
Long-term debt	2,128,149	50.0%	2,130,146	50.2%	2,181,563	51.9%
Shareholders' equity	2,125,993	50.0%	1,965,754	46.3%	2,021,953	48.1%
Total capitalization	$4,254,142	100.0%	$4,246,499	100.0%	$4,203,516	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 50.0 percent at March 31, 2008, 53.7 percent at September 30, 2007 and 51.9 percent at March 31, 2007. 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 six months ended March 31, 2008.

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. Pending regulatory approval, the first cavern is projected to go into operation by early 2011, with the other two caverns projected to be operational by 2012 and 2014. Based on market demand, four additional storage caverns could potentially be developed.

Risk Management Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, 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 fair value hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings. In addition, natural gas inventory would be reflected on the balance sheet at the lower of cost or market instead of at fair value.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our natural gas distribution and natural gas marketing commodity derivative contracts for the three and six months ended March 31, 2008 and 2007:

	Three Months Ended March 31, 2008		Three Months Ended March 31, 2007	
	Natural Gas Distribution	Natural Gas Marketing	Natural Gas Distribution	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(21,528)	$ 51,859	$(33,315)	$ 74,963
Contracts realized/settled	(4,972)	(46,331)	(11,761)	(72,486)
Fair value of new contracts	1,401	—	649	—
Other changes in value	34,604	(28,503)	48,229	(27,471)
Fair value of contracts at end of period	$ 9,505	$(22,975)	$ 3,802	$(24,994)

	Six Months Ended March 31, 2008		Six Months Ended March 31, 2007	
	Natural Gas Distribution	Natural Gas Marketing	Natural Gas Distribution	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(21,053)	$ 26,808	$(27,209)	$ 15,003
Contracts realized/settled	(27,310)	(41,256)	(27,518)	(26,587)
Fair value of new contracts	(280)	—	(1,261)	—
Other changes in value	58,148	(8,527)	59,790	(13,410)
Fair value of contracts at end of period	$ 9,505	$(22,975)	$ 3,802	$(24,994)

The fair value of our natural gas distribution and natural gas marketing derivative contracts at March 31, 2008, is segregated below by time period and fair value source:

	Fair Value of Contracts at March 31, 2008				
	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	$(17,404)	$4,446	$—	$—	$(12,958)
Prices based on models and other valuation methods	(48)	(464)	—	—	(512)
Total Fair Value	$(17,452)	$3,982	$—	$—	$(13,470)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2008 and 2007, our total net periodic pension and other benefits cost was $23.9 million and $24.3 million. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs are capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our total net periodic pension and other benefit costs remained relatively unchanged during the current-year period when compared with the prior-year period as the assumptions we made during our annual pension plan valuation completed June 30, 2007 were consistent with the prior year. 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. At our June 30, 2007 measurement date, the interest rates were consistent with rates at our prior-year measurement date, which resulted in no change to our 6.30 percent discount rate used to determine our fiscal 2008 net periodic and post-retirement cost. In addition, our expected return on our pension plan assets remained constant at 8.25 percent.

During the six months ended March 31, 2008, we contributed $4.7 million to our other postretirement plans, and we expect to contribute a total of approximately $10 million to these plans during fiscal 2008.

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 six-month periods ended March 31, 2008 and 2007.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
METERS IN SERVICE, end of period				
Residential	2,933,980	2,922,314	2,933,980	2,922,314
Commercial	275,998	276,901	275,998	276,901
Industrial	2,269	2,745	2,269	2,745
Public authority and other	8,948	16,718	8,948	16,718
Total meters	3,221,195	3,218,678	3,221,195	3,218,678
INVENTORY STORAGE BALANCE — Bcf	34.4	31.4	34.4	31.4
HEATING DEGREE DAYS(1)				
Actual (weighted average)	1,555	1,575	2,636	2,710
Percent of normal	101%	100%	100%	101%
SALES VOLUMES — MMcf(2)				
Gas sales volumes				
Residential	83,934	82,901	132,965	133,600
Commercial	40,506	39,474	67,126	66,559
Industrial	7,258	7,568	13,212	13,303
Public authority and other	3,870	3,913	7,032	6,794
Total gas sales volumes	135,568	133,856	220,335	220,256
Transportation volumes	40,938	40,811	75,791	74,694
Total throughput	176,506	174,667	296,126	294,950
OPERATING REVENUES (000's)(2)				
Gas sales revenues				
Residential	$ 971,673	$ 925,632	$1,525,962	$1,500,368
Commercial	421,708	402,010	690,177	685,043
Industrial	62,135	64,293	113,311	118,276
Public authority and other	37,244	38,613	67,848	66,357
Total gas sales revenues	1,492,760	1,430,548	2,397,298	2,370,044
Transportation revenues	17,786	19,107	32,791	34,957
Other gas revenues	11,310	11,378	19,944	20,276
Total operating revenues	$1,521,856	$1,461,033	$2,450,033	$2,425,277
Average transportation revenue per Mcf	$ 0.43	$ 0.47	$ 0.43	$ 0.47
Average cost of gas per Mcf sold	$ 8.59	$ 8.33	$ 8.26	$ 8.25

See footnotes following these tables.

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

	Three Months Ended March 31		Six Months Ended March 31	
	2008	2007	2008	2007
CUSTOMERS, end of period				
Industrial	716	717	716	717
Municipal	61	62	61	62
Other	474	453	474	453
Total	1,251	1,232	1,251	1,232
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	19.6	21.2	19.6	21.2
Pipeline, storage and other	1.2	1.0	1.2	1.0
Total	20.8	22.2	20.8	22.2
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	223,476	199,701	412,340	370,319
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	136,677	114,110	245,386	202,148
OPERATING REVENUES (000's)(2)				
Regulated transmission and storage	$ 51,440	$ 46,068	$ 96,486	$ 85,940
Natural gas marketing	1,128,653	795,041	1,969,370	1,506,735
Pipeline, storage and other	10,022	14,077	16,749	25,410
Total operating revenues	$1,190,115	$855,186	$2,082,605	$1,618,085

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Generally, normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the year ended September 30, 2007. During the six months ended March 31, 2008, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of March 31, 2008. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed by the Company in the reports we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the six months ended March 31, 2008, 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 environmental-related matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the year ended September 30, 2007. 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.

Item 4. *Submission of Matters to a Vote of Security Holders*

At the Annual Meeting of Shareholders of Atmos Energy Corporation on February 6, 2008, 75,769,041 votes were cast as follows:

	Votes For	Votes Withheld	Votes Abstaining	Broker Non-Votes
Class I Directors:				
Travis W. Bain II	74,817,823	951,218	—	—
Dan Busbee	74,820,363	948,678	—	—
Richard W. Douglas	73,997,241	1,771,800	—	—
Richard K. Gordon	74,984,609	784,432	—	—
Ratification of the Audit Committee's engagement of Ernst & Young LLP to serve as the Company's registered independent public accounting firm for fiscal year 2008	75,295,028	334,699	139,314	—

The term of the Class I directors, Travis W. Bain II, Dan Busbee, Richard W. Douglas and Richard K. Gordon, will expire in 2011. The term of the Class II directors, Richard W. Cardin, Thomas C. Meredith, Nancy K. Quinn, Stephen R. Springer and Richard Ware II, will expire in 2009. The term of the Class III directors, Robert W. Best, Thomas J. Garland, Phillip E. Nichol and Charles K. Vaughan, will expire in 2010.

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.

SIGNATURES

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/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: May 6, 2008

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number
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.

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

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2007

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of January 30, 2007.

Class	Shares Outstanding
No Par Value	89,957,651

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
KCC	Kansas Corporation Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TRA	Tennessee Regulatory Authority
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2007	September 30, 2007
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,467,260	$5,396,070
Less accumulated depreciation and amortization	1,579,134	1,559,234
Net property, plant and equipment	3,888,126	3,836,836
Current assets		
Cash and cash equivalents	51,874	60,725
Cash held on deposit in margin account	—	—
Accounts receivable, net	776,866	380,133
Gas stored underground	564,426	515,128
Other current assets	126,855	112,909
Total current assets	1,520,021	1,068,895
Goodwill and intangible assets	737,536	737,692
Deferred charges and other assets	254,080	253,494
	$6,399,763	$5,896,917
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2007 — 89,906,989 shares; September 30, 2007 — 89,326,537 shares	$ 450	$ 447
Additional paid-in capital	1,713,043	1,700,378
Retained earnings	325,183	281,127
Accumulated other comprehensive loss	(6,193)	(16,198)
Shareholders' equity	2,032,483	1,965,754
Long-term debt	2,124,915	2,126,315
Total capitalization	4,157,398	4,092,069
Current liabilities		
Accounts payable and accrued liabilities	739,807	355,255
Other current liabilities	389,937	409,993
Short-term debt	202,244	150,599
Current maturities of long-term debt	3,618	3,831
Total current liabilities	1,335,606	919,678
Deferred income taxes	378,425	370,569
Regulatory cost of removal obligation	279,625	271,059
Deferred credits and other liabilities	248,709	243,542
	$6,399,763	$5,896,917

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2007	2006
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 928,177	$ 964,244
Regulated transmission and storage segment	45,046	39,872
Natural gas marketing segment	840,717	711,694
Pipeline, storage and other segment	6,727	11,333
Intersegment eliminations	(163,157)	(124,510)
	1,657,510	1,602,633
Purchased gas cost		
Natural gas distribution segment	654,977	701,676
Regulated transmission and storage segment	—	—
Natural gas marketing segment	794,754	648,560
Pipeline, storage and other segment	729	225
Intersegment eliminations	(162,588)	(123,420)
	1,287,872	1,227,041
Gross profit	369,638	375,592
Operating expenses		
Operation and maintenance	121,189	115,370
Depreciation and amortization	48,513	48,995
Taxes, other than income	41,427	40,067
Total operating expenses	211,129	204,432
Operating income	158,509	171,160
Miscellaneous income (expense)	(93)	1,579
Interest charges	36,817	39,532
Income before income taxes	121,599	133,207
Income tax expense	47,796	51,946
Net income	$ 73,803	$ 81,261
Basic net income per share	$ 0.83	$ 0.98
Diluted net income per share	$ 0.82	$ 0.97
Cash dividends per share	$ 0.325	$ 0.320
Weighted average shares outstanding:		
Basic	89,006	82,726
Diluted	89,608	83,350

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2007	2006
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 73,803	$ 81,261
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	48,513	48,995
Charged to other accounts	23	83
Deferred income taxes	11,978	13,869
Other	4,406	4,718
Net assets / liabilities from risk management activities	(11,586)	(34,857)
Net change in operating assets and liabilities	(65,700)	50,900
Net cash provided by operating activities	61,437	164,969
Cash Flows From Investing Activities		
Capital expenditures	(94,155)	(86,986)
Other, net	(1,874)	(1,324)
Net cash used in investing activities	(96,029)	(88,310)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	50,690	(227,945)
Repayment of long-term debt	(1,741)	(1,717)
Cash dividends paid	(29,178)	(26,261)
Issuance of common stock	5,970	5,594
Net proceeds from equity offering	—	192,261
Net cash provided by (used in) financing activities	25,741	(58,068)
Net increase (decrease) in cash and cash equivalents	(8,851)	18,591
Cash and cash equivalents at beginning of period	60,725	75,815
Cash and cash equivalents at end of period	$ 51,874	$ 94,406

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2007

1. Nature of Business

Atmos Energy Corporation ("Atmos" 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 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, 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 locations 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 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 in 22 states 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 managed by 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 southeastern and midwestern states 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 derivative instruments.

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by AEH. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Through December 31, 2006, AES provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Effective January 1, 2007, our shared services function began providing these services to our natural gas distribution operations. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

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 its Annual Report on Form 10-K for the fiscal year ended September 30, 2007. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2007 are not indicative of expected results of operations for the full 2008 fiscal year, which ends September 30, 2008.

Significant accounting policies

Our accounting policies are described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2007. Except for the Company's adoption of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48), discussed below, there were no significant changes to those accounting policies during the three months ended December 31, 2007.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN 48 on October 1, 2007. As a result of adopting FIN 48, we determined that we had $6.1 million of liabilities associated with uncertain tax positions. Of this amount, $0.5 million was recognized as a result of adopting FIN 48 with an offsetting reduction to retained earnings. As of December 31, 2007, we had recorded liabilities associated with uncertain tax positions totaling $6.1 million. The realization of all of these tax benefits would reduce our income tax expense by approximately $6.1 million.

Prior to October 1, 2007, the $5.6 million liability previously recorded for uncertain tax positions was reflected on the consolidated balance sheet as a component of deferred income taxes. As a result of adopting FIN 48, we recorded a $3.7 million liability as a component of other current liabilities and $2.4 million as a component of deferred credits and other liabilities, with offsetting decreases to the deferred income tax liability.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. For the three months ended December 31, 2007 we recognized $0.2 million in penalties and interest.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2001. The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns, and we anticipate these examinations will be completed by the end of fiscal 2008. We believe all material tax items which relate to the years under audit have been properly accrued.

Regulatory assets and liabilities

We record certain costs as regulatory assets in accordance with Statement of Financial Accounting Standards (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 separately reported.

Significant regulatory assets and liabilities as of December 31, 2007 and September 30, 2007 included the following:

	December 31, 2007	September 30, 2007
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 56,889	$ 59,022
Merger and integration costs, net	7,893	7,996
Deferred gas cost	52,164	14,797
Environmental costs	1,270	1,303
Rate case costs	11,737	10,989
Deferred franchise fees	776	796
Other	10,299	10,719
	$141,028	$105,622
Regulatory liabilities:		
Deferred gas cost	$ 43,162	$ 84,043
Regulatory cost of removal obligation	299,401	295,241
Deferred income taxes, net	165	165
Other	7,433	7,503
	$350,161	$386,952

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.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2007 and 2006:

	Three Months Ended December 31	
	2007	2006
	(In thousands)	
Net income	$73,803	$81,261
Unrealized holding gains on investments, net of tax expense of $714 and $883	1,165	1,441
Amortization of interest rate hedging transactions, net of tax expense of $482 and $528	787	860
Net unrealized gains on commodity hedging transactions, net of tax expense of $4,937 and $7,219	8,053	11,778
Comprehensive income	$83,808	$95,340

Accumulated other comprehensive loss, net of tax, as of December 31, 2007 and September 30, 2007 consisted of the following unrealized gains (losses):

	December 31, 2007	September 30, 2007
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,972	$ 2,807
Treasury lock agreements	(13,465)	(14,252)
Cash flow hedges	3,300	(4,753)
	$ (6,193)	$(16,198)

Recently issued accounting pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 141 (revised 2007), *Business Combinations*. SFAS 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS 141(R) significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under SFAS 141(R), changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. The provisions of this standard will apply to acquisitions we complete after October 1, 2009.

In December 2007, the FASB issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statement, an amendment of ARB No. 51*. SFAS 160 changes the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. The provisions of the standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

3. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at December 31, 2007 and September 30, 2007:

	Natural Gas Distribution	Natural Gas Marketing	Total
		(In thousands)	
December 31, 2007:			
Assets from risk management activities, current	$ —	$46,660	$ 46,660
Assets from risk management activities, noncurrent	—	6,362	6,362
Liabilities from risk management activities, current	(21,528)	(952)	(22,480)
Liabilities from risk management activities, noncurrent	—	(211)	(211)
Net assets (liabilities)	$(21,528)	$51,859	$ 30,331
September 30, 2007:			
Assets from risk management activities, current	$ —	$21,849	$ 21,849
Assets from risk management activities, noncurrent	—	5,535	5,535
Liabilities from risk management activities, current	(21,053)	(286)	(21,339)
Liabilities from risk management activities, noncurrent	—	(290)	(290)
Net assets (liabilities)	$(21,053)	$26,808	$ 5,755

Natural Gas Distribution Hedging Activities

We use a combination of physical storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. Because the gains or losses of financial derivatives used in our natural gas distribution segment ultimately are recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial derivatives.

Nonregulated Hedging Activities

AEH manages its exposure to the risk of natural gas price changes through a combination of physical storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our financial derivative activities include fair value hedges to offset changes in the fair value of our natural gas inventory and cash flow hedges to offset anticipated purchases and sales of gas in the future. AEH also utilizes basis swaps and other non-hedge derivative instruments to manage its exposure to market volatility.

For the three-month period ended December 31, 2007, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to increases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the three months ended December 31, 2007 of $5.5 million in net deferred hedging losses in net income when the derivative contracts matured according to their terms. The net deferred hedging gain associated with open cash flow hedges remains subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Most of the deferred hedging balance as of December 31, 2007 is expected to be recognized in net income in fiscal 2008 along with the corresponding hedged purchases and sales of natural gas.

Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative hedging instrument and the hedged item and could materially affect our results as ineffectiveness is recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments is referred to as basis ineffectiveness. Fair value hedge ineffectiveness arising from the timing of the settlement of physical contracts and the settlement of the related fair value hedge is referred to as timing ineffectiveness. Gains and losses arising from basis and timing ineffectiveness for the three months ended December 31, 2007 and 2006 are as follows:

	Three Months Ended December 31	
	2007	2006
	(In thousands)	
Basis ineffectiveness:		
Fair value basis ineffectiveness	$1,956	$ (646)
Cash flow basis ineffectiveness	759	124
Total basis ineffectiveness	2,715	(522)
Timing ineffectiveness:		
Fair value timing ineffectiveness	99	(1,284)
Total hedge ineffectiveness	$2,814	$(1,806)

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no net 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. We may 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 December 31, 2007, AEH had a net open position (including existing storage) of 0.1 Bcf.

4. Debt

Long-term debt

Long-term debt at December 31, 2007 and September 30, 2007 consisted of the following:

	December 31, 2007	September 30, 2007
	(In thousands)	
Unsecured 4.00% Senior Notes, due 2009	$ 400,000	$ 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 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 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
First Mortgage Bonds		
Series P, 10.43% due 2013	6,250	7,500
Other term notes due in installments through 2013	3,399	3,890
Total long-term debt	2,131,952	2,133,693
Less:		
Original issue discount on unsecured senior notes and debentures	(3,419)	(3,547)
Current maturities	(3,618)	(3,831)
	$2,124,915	$2,126,315

Short-term debt

At December 31, 2007 and September 30, 2007, there was $202.2 million and $150.6 million outstanding under our commercial paper program and bank credit facilities.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of December 31, 2007, we had approximately $450 million of availability remaining under the registration statement. Due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all of the three credit rating agencies was achieved.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of December 31, 2007, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a five-year unsecured facility, expiring December 2011, for $600 million that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At December 31, 2007, there was $202.2 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility for $300 million that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This facility was replaced by another 364-day facility in November 2007 with no material changes to its terms and pricing. At December 31, 2007, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expires in March 2008. At December 31, 2007, there were no borrowings under this facility.

The availability of funds under our 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 our revolving credit 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 December 31, 2007, our total-debt-to-total-capitalization ratio, as defined, was 56 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt-to-total-capitalization ratio.

Uncommitted credit facilities

AEM has a $580 million uncommitted demand working capital credit facility that expires March 31, 2008. Borrowings under the credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate defined as the higher of (i) 0.50 percent per annum above the Federal Funds rate or (ii) the lender's prime rate plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR for the applicable interest period plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility not to exceed a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss for the most recent 12 month accounting period exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At December 31, 2007, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.91 to 1.

At December 31, 2007, there were no borrowings outstanding under this credit facility. However, at December 31, 2007, AEM letters of credit totaling $129.9 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 $70.1 million at December 31, 2007. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

The Company also has an unsecured short-term uncommitted credit line of $25 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at December 31, 2007, but letters of credit reduced the amount available by $5.4 million. In January 2008, the unused portion of this facility was terminated by the bank and the remaining balance will be terminated as the outstanding letters of credit expire.

The Company has a $200 million intercompany uncommitted revolving credit facility with AEH. This facility bears interest at the lesser of (i) LIBOR plus 0.20 percent or (ii) the marginal borrowing rate available to the Company on any such date under its commercial paper program. Applicable state regulatory commissions have approved this facility through December 31, 2008. At December 31, 2007, there was $57.5 million outstanding under this facility.

AEH has a $200 million intercompany uncommitted demand credit facility with the Company which bears interest at the rate of AEM's $580 million uncommitted demand working capital credit facility plus 0.25 percent. Applicable state regulatory commissions have approved this facility through December 31, 2008. At December 31, 2007, there were no borrowings under this facility.

In addition, to supplement its $580 million credit facility, AEM has a $175 million intercompany uncommitted demand credit facility with AEH, which bears interest at LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility. At December 31, 2007, there were no borrowings under this facility.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9 million. At December 31, 2007 approximately $304.8 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of December 31, 2007. If we were unable to comply with our debt covenants, we could be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. 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. In addition, 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. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no 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.

5. Public Offering

On December 13, 2006, we completed the public offering of 6,325,000 shares of our common stock including the underwriters' exercise of their overallotment option of 825,000 shares. The offering was priced at $31.50 and generated net proceeds of approximately $192 million. We used the net proceeds from this offering to reduce short-term debt.

6. Earnings Per Share

Basic and diluted earnings per share for the three months ended December 31, 2007 and 2006 are calculated as follows:

	Three Months Ended December 31	
	2007	2006
	(In thousands, except per share amounts)	
Net income	$73,803	$81,261
Denominator for basic income per share — weighted average common shares	89,006	82,726
Effect of dilutive securities:		
Restricted and other shares	496	453
Stock options	106	171
Denominator for diluted income per share — weighted average common shares	89,608	83,350
Income per share — basic	$ 0.83	$ 0.98
Income per share — diluted	$ 0.82	$ 0.97

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended December 31, 2007 and 2006 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 months ended December 31, 2007 and 2006 are presented in the following table. All 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 December 31			
	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,878	$ 4,018	$3,341	$2,807
Interest cost	6,736	6,495	2,912	2,640
Expected return on assets	(6,310)	(6,089)	(715)	(597)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(171)	45	—	8
Amortization of actuarial loss	1,926	2,434	—	—
Net periodic pension cost	$ 6,059	$ 6,903	$5,916	$5,236

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2007 and 2006 are as follows:

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
Discount rate	6.30%	6.30%	6.30%	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%	5.20%

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 is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made to satisfy regulatory requirements in certain of our jurisdictions. During the three months ended December 31, 2007, we contributed $2.1 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2008.

8. Commitments and Contingencies

Litigation and Environmental Matters

On December 13, 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. The data requests include requests for information and documents concerning specified short-term capacity release transportation transactions. We have submitted our responses to the data requests on a timely basis and we intend to fully cooperate with the Commission during its investigation. The Company is currently unable to predict the final outcome of this investigation or the potential impact it could have on the Company's results of operations, financial condition or cash flows.

The Texas Railroad Commission recently issued a directive and is currently developing a rulemaking concerning the replacement of compression couplings at pre-bent gas meter risers which could affect all natural gas utility companies operating in Texas. Compliance with the directive along with adoption of the pending rulemaking will require us to re-direct significant capital spending. These amounts should be recoverable through our rates.

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to our Annual Report on Form 10-K for the year ended September 30, 2007, except as noted above, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2007. 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 December 31, 2007, AEM was committed to purchase 82.1 Bcf within one year, 32.1 Bcf within one to three years and 0.2 Bcf after three years under indexed contracts. AEM is committed to purchase 2.0 Bcf within one year under fixed price contracts with prices ranging from $6.27 to $9.85. Purchases under these contracts totaled $572.0 million and $420.4 million for the three months ended December 31, 2007 and 2006.

Our natural gas distribution operations, other than the 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 its service area which obligate it to purchase specified volumes at market prices. The estimated fiscal year commitments under these contracts as of December 31, 2007 are as follows (in thousands):

2008	$295,493
2009	168,373
2010	107,259
2011	9,871
2012	10,057
Thereafter	13,648
	$604,701

Regulatory Matters

At December 31, 2007, we had rate cases in progress in our Kansas and Mid-Tex service areas. In January 2008, we reached a tentative settlement agreement with the Atmos Cities Steering Committee, which represents over half of our Mid-Tex customers. We remain in negotiations with cities which represent the majority of the remaining Mid-Tex customers. In our Kansas rate case, we are currently providing information to and addressing questions raised by the regulatory commission. We believe we will be able to demonstrate to these regulators that our rates are just and reasonable. 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 15 to our Annual Report on Form 10-K for the year ended September 30, 2007. During the three months ended December 31, 2007, there were no material changes in our concentration of credit risk.

10. Segment Information

Atmos Energy Corporation and our subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage businesses as well as certain other nonregulated 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 provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

Our operations are divided into 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.

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, 2007. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three-month periods ended December 31, 2007 and 2006 by segment are presented in the following tables:

	Three Months Ended December 31, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$928,029	$22,437	$702,722	$4,322	$ —	$1,657,510
Intersegment revenues	148	22,609	137,995	2,405	(163,157)	—
	928,177	45,046	840,717	6,727	(163,157)	1,657,510
Purchased gas cost	654,977	—	794,754	729	(162,588)	1,287,872
Gross profit	273,200	45,046	45,963	5,998	(569)	369,638
Operating expenses						
Operation and maintenance	97,247	15,432	7,877	1,288	(655)	121,189
Depreciation and amortization	42,832	4,916	387	378	—	48,513
Taxes, other than income	35,618	2,444	3,000	365	—	41,427
Total operating expenses	175,697	22,792	11,264	2,031	(655)	211,129
Operating income	97,503	22,254	34,699	3,967	86	158,509
Miscellaneous income (expense)	476	174	796	2,028	(3,567)	(93)
Interest charges	31,214	7,071	1,314	699	(3,481)	36,817
Income before income taxes	66,765	15,357	34,181	5,296	—	121,599
Income tax expense	26,601	5,510	13,581	2,104	—	47,796
Net income	$ 40,164	$ 9,847	$ 20,600	$3,192	$ —	$ 73,803
Capital expenditures	$ 84,313	$ 8,382	$ 31	$1,429	$ —	$ 94,155

	Three Months Ended December 31, 2006					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$964,083	$18,677	$611,369	$ 8,504	$ —	$1,602,633
Intersegment revenues	161	21,195	100,325	2,829	(124,510)	—
	964,244	39,872	711,694	11,333	(124,510)	1,602,633
Purchased gas cost	701,676	—	648,560	225	(123,420)	1,227,041
Gross profit	262,568	39,872	63,134	11,108	(1,090)	375,592
Operating expenses						
Operation and maintenance	98,113	11,102	5,578	1,753	(1,176)	115,370
Depreciation and amortization	43,722	4,517	329	427	—	48,995
Taxes, other than income	37,622	1,936	249	260	—	40,067
Total operating expenses	179,457	17,555	6,156	2,440	(1,176)	204,432
Operating income	83,111	22,317	56,978	8,668	86	171,160
Miscellaneous income	1,780	329	1,716	900	(3,146)	1,579
Interest charges	32,473	7,491	1,027	1,601	(3,060)	39,532
Income before income taxes	52,418	15,155	57,667	7,967	—	133,207
Income tax expense	20,584	5,504	22,720	3,138	—	51,946
Net income	$ 31,834	$ 9,651	$ 34,947	$ 4,829	$ —	$ 81,261
Capital expenditures	$ 72,419	$13,604	$ 338	$ 625	$ —	$ 86,986

Balance sheet information at December 31, 2007 and September 30, 2007 by segment is presented in the following tables:

	December 31, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,299,203	$533,924	$ 7,705	$ 47,294	$ —	$3,888,126
Investment in subsidiaries	438,168	—	(2,096)	—	(436,072)	—
Current assets						
Cash and cash equivalents	29,328	—	22,379	167	—	51,874
Cash held on deposit in margin account	—	—	—	—	—	—
Assets from risk management activities	—	—	46,720	15,868	(15,928)	46,660
Other current assets	979,538	19,848	449,016	68,541	(95,456)	1,421,487
Intercompany receivables	532,563	—	—	137,116	(669,679)	—
Total current assets	1,541,429	19,848	518,115	221,692	(781,063)	1,520,021
Intangible assets	—	—	2,560	—	—	2,560
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	6,362	—	—	6,362
Deferred charges and other assets	222,307	6,333	3,787	15,291	—	247,718
	$6,068,882	$692,595	$560,715	$294,706	$(1,217,135)	$6,399,763
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,032,483	$ 98,565	$134,782	$204,821	$ (438,168)	$2,032,483
Long-term debt	2,123,884	—	—	1,031	—	2,124,915
Total capitalization	4,156,367	98,565	134,782	205,852	(438,168)	4,157,398
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,368	—	3,618
Short-term debt	259,731	—	—	—	(57,487)	202,244
Liabilities from risk management activities	21,528	—	16,835	45	(15,928)	22,480
Other current liabilities	776,603	8,774	288,207	69,553	(35,873)	1,107,264
Intercompany payables	—	545,120	124,559	—	(669,679)	—
Total current liabilities	1,059,112	553,894	429,601	71,966	(778,967)	1,335,606
Deferred income taxes	333,463	36,540	(4,587)	13,009	—	378,425
Noncurrent liabilities from risk management activities	—	—	211	—	—	211
Regulatory cost of removal obligation	279,625	—	—	—	—	279,625
Deferred credits and other liabilities	240,315	3,596	708	3,879	—	248,498
	$6,068,882	$692,595	$560,715	$294,706	$(1,217,135)	$6,399,763

	September 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,251,144	$531,921	$ 7,850	$ 45,921	$ —	$3,836,836
Investment in subsidiaries	396,474	—	(2,096)	—	(394,378)	—
Current assets						
Cash and cash equivalents	28,881	—	31,703	141	—	60,725
Cash held on deposit in margin account	—	—	—	—	—	—
Assets from risk management activities	—	—	26,783	12,947	(17,881)	21,849
Other current assets	643,353	20,065	337,169	76,731	(90,997)	986,321
Intercompany receivables	536,985	—	—	114,300	(651,285)	—
Total current assets	1,209,219	20,065	395,655	204,119	(760,163)	1,068,895
Intangible assets	—	—	2,716	—	—	2,716
Goodwill	567,775	132,490	24,282	10,429	—	734,976
Noncurrent assets from risk management activities	—	—	5,535	—	—	5,535
Deferred charges and other assets	227,869	4,898	1,279	13,913	—	247,959
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,965,754	$ 88,719	$107,090	$200,665	$ (396,474)	$1,965,754
Long-term debt	2,125,007	—	—	1,308	—	2,126,315
Total capitalization	4,090,761	88,719	107,090	201,973	(396,474)	4,092,069
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,581	—	3,831
Short-term debt	187,284	—	30,000	—	(66,685)	150,599
Liabilities from risk management activities	21,053	—	18,167	—	(17,881)	21,339
Other current liabilities	519,642	6,394	186,792	53,297	(22,216)	743,909
Intercompany payables	—	550,184	101,101	—	(651,285)	—
Total current liabilities	729,229	556,578	336,060	55,878	(758,067)	919,678
Deferred income taxes	326,518	40,565	(8,925)	12,411	—	370,569
Noncurrent liabilities from risk management activities	—	—	290	—	—	290
Regulatory cost of removal obligation	271,059	—	—	—	—	271,059
Deferred credits and other liabilities	234,914	3,512	706	4,120	—	243,252
	$5,652,481	$689,374	$435,221	$274,382	$(1,154,541)	$5,896,917

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of December 31, 2007, and the related condensed consolidated statements of income for the three-month periods ended December 31, 2007 and 2006, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2007 and 2006. 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, 2007, 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 27, 2007, 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, 2007, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

ERNST & YOUNG LLP

Dallas, Texas
February 4, 2008

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, 2007.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar 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 year ended September 30, 2007, include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in one state; adverse weather conditions; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; the capital-intensive nature of our distribution business, increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the impact of environmental regulations on our business; the inherent hazards and risks involved in operating our distribution business, natural disasters, terrorist activities or other events; and other uncertainties, which may be discussed herein, including the outcome of any pending federal or state regulatory investigations, 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 Corporation 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 in 22 states and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties.

Our operations are divided into 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, 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 year ended September 30, 2007 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 by the Audit Committee quarterly. There have been no significant changes to these critical accounting policies during the three months ended December 31, 2007.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three-month periods ended December 31, 2007 and 2006:

	Three Months Ended December 31	
	2007	2006
	(In thousands, except per share data)	
Operating revenues	$1,657,510	$1,602,633
Gross profit	369,638	375,592
Operating expenses	211,129	204,432
Operating income	158,509	171,160
Miscellaneous income (expense)	(93)	1,579
Interest charges	36,817	39,532
Income before income taxes	121,599	133,207
Income tax expense	47,796	51,946
Net income	$ 73,803	$ 81,261
Diluted net income per share	$ 0.82	$ 0.97

Our consolidated net income during the three months ended December 31, 2007 and 2006 was earned across our business segments as follows:

	Three Months Ended December 31		
	2007	2006	Change
	(In thousands)		
Natural gas distribution segment	$40,164	$31,834	$ 8,330
Regulated transmission and storage segment	9,847	9,651	196
Natural gas marketing segment	20,600	34,947	(14,347)
Pipeline, storage and other segment	3,192	4,829	(1,637)
Net income	$73,803	$81,261	$ (7,458)

The following table segregates our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended December 31		
	2007	2006	Change
	(In thousands, except per share data)		
Regulated operations	$50,011	$41,485	$ 8,526
Nonregulated operations	23,792	39,776	(15,984)
Consolidated net income	$73,803	$81,261	$ (7,458)
Diluted EPS from regulated operations	$ 0.56	$ 0.50	$ 0.06
Diluted EPS from nonregulated operations	0.26	0.47	(0.21)
Consolidated diluted EPS	$ 0.82	$ 0.97	$ (0.15)

The following summarizes the results of our operations and other significant events for the three months ended December 31, 2007:

- Regulated operations generated 68 percent of net income during the current-year quarter compared to 51 percent in the prior-year quarter. The $8.5 million increase in our regulated operations net income reflects rate increases in our Mid-Tex, Kentucky, Louisiana and Tennessee service areas coupled with higher rates and throughput in our Atmos Pipeline — Texas Division.
- Nonregulated operations contributed 32 percent of net income during the current-year quarter compared to 49 percent in the prior-year quarter. The $16.0 million decrease in our nonregulated operations net income primarily reflects lower unrealized and delivered gas margins, partially offset by lower realized losses.
- For the three months ended December 31, 2007, we generated $61.4 million in operating cash flow compared with $165.0 million for the three months ended December 31, 2006, primarily reflecting the utilization of lower income tax receivable balances coupled with the unfavorable timing of payments for various working capital items.
- In September 2007, we filed a statement of intent for a rate increase of $51.9 million in our Mid-Tex Division. In January 2008, we reached a tentative settlement agreement with the Atmos Cities Steering Committee, which represents over half of our Mid-Tex customers. The settlement agreement contains various rate changes including an increase of approximately 20 cents per month on an average residential customer's bill and a rate review mechanism that will reflect annual changes in the Mid-Tex Division's cost of service and rate base.

Three Months Ended December 31, 2007 compared with Three Months Ended December 31, 2006

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 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, beginning with the 2006-2007 winter heating season, 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. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences can be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income.

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.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2007 and 2006 are presented below.

	Three Months Ended December 31		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Gross profit	$273,200	$262,568	$10,632
Operating expenses	175,697	179,457	(3,760)
Operating income	97,503	83,111	14,392
Miscellaneous income	476	1,780	(1,304)
Interest charges	31,214	32,473	(1,259)
Income before income taxes	66,765	52,418	14,347
Income tax expense	26,601	20,584	6,017
Net income	$ 40,164	$ 31,834	$ 8,330
Consolidated natural gas distribution sales volumes — MMcf	84,767	86,400	(1,633)
Consolidated natural gas distribution transportation volumes — MMcf	33,749	32,694	1,055
Total consolidated natural gas distribution throughput — MMcf	118,516	119,094	(578)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.44	$ 0.48	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.73	$ 8.12	$ (0.39)

The following table shows our operating income by natural gas distribution division for the three months ended December 31, 2007 and 2006. 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 December 31		
	2007	2006	Change
	(In thousands)		
Colorado-Kansas	$ 6,688	$ 8,672	$ (1,984)
Kentucky/Mid-States	14,168	14,203	(35)
Louisiana	11,932	10,593	1,339
Mid-Tex	50,225	35,340	14,885
Mississippi	7,829	7,599	230
West Texas	4,976	6,506	(1,530)
Other	1,685	198	1,487
Total	$97,503	$83,111	$14,392

The $10.6 million increase in natural gas distribution gross profit primarily reflects a $9.3 million net increase in rates. The net increase in rates primarily was attributable to the Mid-Tex Division which increased $6.6 million as a result of the 2006 Gas Reliability Infrastructure Program (GRIP) filing and the Mid-Tex rate case, which was substantially concluded in March 2007. The current-year period also reflects $3.4 million in rate increases in our Kentucky, Louisiana and Tennessee service areas.

Gross profit also increased approximately $2.0 million in revenue-related taxes primarily due to higher revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This increase, coupled with a $1.7 million quarter-over-quarter increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income resulted in a $3.7 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 and taxes, other than income, decreased by $3.8 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $0.9 million, primarily due to increased administrative and natural gas odorization costs partially offset by lower employee costs. The increase in operation and maintenance expense also includes costs associated with the transfer of our gas supply function from our pipeline, storage and other segment to our natural gas distribution segment effective January 1, 2007.

The provision for doubtful accounts decreased $1.8 million to $4.6 million for the three months ended December 31, 2007. The decrease primarily was attributable to lower revenues associated with lower natural gas prices. In the natural gas distribution segment, the average cost of natural gas for the three months ended December 31, 2007 was $7.73 per Mcf, compared with $8.12 per Mcf for the three months ended December 31, 2006.

Depreciation and amortization expense decreased $0.9 million for the first quarter of fiscal 2008 compared with first quarter of fiscal 2007. The decrease primarily was attributable to changes in depreciation rates as a result of recent rate cases.

Interest charges allocated to the natural gas distribution segment decreased $1.3 million due to lower average outstanding short-term debt balances in the current-year period compared with the prior-year period.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the three months ended December 31, 2007 are discussed below. The amounts described below represent the gross revenues that were requested or received in each rate filing, which may not necessarily reflect the increase in operating income obtained, as certain operating costs may have increased as a result of a commission's final ruling.

Mid-Tex Division Tentative Rate Settlement

In September 2007, Atmos filed a statement of intent for a rate increase of $51.9 million in our Mid-Tex Division. In January 2008, we reached a tentative settlement agreement with the Atmos Cities Steering Committee (ACSC), which represents approximately 52 percent of the Mid-Tex customers. The settlement agreement includes i) an increase of approximately 20 cents per month on an average residential customer's bill; ii) a rate review mechanism that will reflect annual changes in the Mid-Tex Division's cost of service and rate base; iii) an authorized return on equity of 9.6 percent; and iv) the establishment of a new program designed to encourage natural gas conservation. The settlement agreement reached with ACSC is subject to approval by each of the cities it represents. The Company remains in negotiations with cities which represent the majority of the remaining Mid-Tex customers. Hearings are set to begin in February 2008 for the cities with whom we have not reached a tentative settlement.

Other Rate Case Filings

In May 2006, Atmos began receiving "show cause" ordinances from several of the cities in the West Texas Division. In December 2007, our West Texas Division reached a settlement agreement with the West Texas cities resulting in an approved GRIP filing with an increase in annual revenues of approximately $1.1 million, as discussed below. The settlement agreement also includes an agreement to work on a rate revenue mechanism to be developed by Atmos and the West Texas cities during 2008 which will adjust rates to reflect periodic changes in the West Texas Division's cost of service and rate base and the dismissal of all pending show cause actions.

In October 2007, our Kentucky/Mid-States Division settled its $11.1 million rate case filed in May 2007 with the Tennessee Regulatory Authority. The settlement resulted in an increase in annual revenue of $4.0 million and a $4.1 million reduction in depreciation expense.

In September 2007, we filed an application with the Kansas Corporation Commission (KCC) requesting a rate increase of $5.0 million in our Kansas service area. Hearings are scheduled for March 2008.

GRIP Filings

In December 2007, the Railroad Commission of Texas approved the GRIP filing for our West Texas Division to include in rate base approximately $7.0 million of capital costs incurred during calendar year 2006. The filing should result in additional annual revenues of approximately $1.1 million.

Stable Rate Filings

Louisiana Division. In December 2007, we filed our annual rate stabilization clause requesting an increase of $2.2 million including an increase in depreciation expense of approximately $0.4 million. The filing was for the test year ended September 30, 2007 and the rate change is expected to be effective April 1, 2008.

Mississippi Division. In December 2007, the Mississippi Commission approved our annual stable rate filing with no change in rates.

Regulated Transmission and Storage Segment

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

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2007 and 2006 are presented below.

	Three Months Ended December 31		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 22,388	$ 20,464	$ 1,924
Third-party transportation	18,232	14,653	3,579
Storage and park and lend services	2,039	3,174	(1,135)
Other	2,387	1,581	806
Gross profit	45,046	39,872	5,174
Operating expenses	22,792	17,555	5,237
Operating income	22,254	22,317	(63)
Miscellaneous income	174	329	(155)
Interest charges	7,071	7,491	(420)
Income before income taxes	15,357	15,155	202
Income tax expense	5,510	5,504	6
Net income	$ 9,847	$ 9,651	$ 196
Consolidated pipeline transportation volumes — MMcf	136,200	116,813	19,387

The $5.2 million increase in gross profit primarily was attributable to a $2.6 million increase from rate adjustments resulting from our 2006 GRIP filing and a $2.0 million increase from transportation volumes. Throughput increased 17 percent primarily due to increased transportation in the Barnett Shale and Carthage regions of Texas. The improvement in gross profit also reflects increased unit transportation margins due to favorable market conditions which contributed $0.9 million. These increases were partially offset by a $1.1 million decrease in storage, parking and lending services due to market conditions.

Operating expenses increased $5.2 million primarily due to increased pipeline integrity and maintenance costs.

Natural Gas Marketing Segment

Our natural gas marketing segment 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 derivative products. 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.

To optimize the storage and transportation capacity we own or control, we 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. Additionally, we engage 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 contracts at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and derivative contracts, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Atmos Energy Marketing, LLC (AEM) continually manages its net physical position to enhance the future economic profit it captured when an original transaction was executed. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective.

The natural gas inventory used in our natural gas marketing storage activities is marked to market at the end of each month based upon the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. We use derivatives, designated as fair value hedges, to hedge this natural gas inventory. These derivatives 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. 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 the unrealized margins reported as a part of our storage activities until the underlying physical gas is cycled and the related financial derivatives are settled.

AEM also uses derivative instruments to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original physical inventory hedge and to insulate and protect the economic value within its storage and marketing activities. Changes in fair value associated with these financial instruments are recognized as unrealized gains and losses within AEM's storage and marketing activities 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 December 31, 2007 and 2006 are presented below. Gross profit margin for our natural gas marketing segment consists primarily of margins earned from the delivery of gas and related services requested by our customers and asset optimization activities, which are derived from the utilization of our managed proprietary and 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 the derivative contracts used by our natural gas marketing segment to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical 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 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 December 31		
	2007	2006	Change
	(In thousands, unless otherwise noted)		
Delivered gas	$18,173	$20,069	$ (1,896)
Asset optimization	(525)	(5,790)	5,265
Unrealized margins	28,315	48,855	(20,540)
Gross profit	45,963	63,134	(17,171)
Operating expenses	11,264	6,156	5,108
Operating income	34,699	56,978	(22,279)
Miscellaneous income	796	1,716	(920)
Interest charges	1,314	1,027	287
Income before income taxes	34,181	57,667	(23,486)
Income tax expense	13,581	22,720	(9,139)
Net income	$20,600	$34,947	$(14,347)
Consolidated natural gas marketing sales volumes — MMcf	96,206	77,526	18,680
Net physical position (Bcf)	17.7	21.0	(3.3)

The $17.2 million decrease in our natural gas marketing segment's gross profit primarily reflects a $20.5 million decrease in unrealized margins attributable to wider physical/financial spreads experienced during the current-year quarter compared with the prior-year quarter.

Gross profit also reflected a $1.9 million decrease in delivered gas margins. This decrease reflects the impact of a less volatile market, which reduced opportunities to take advantage of pricing differences between hubs, partially offset by a 24 percent increase in sales volumes attributable to successful execution of our marketing strategies.

These decreases were partially offset by lower realized losses incurred on the settlement of financial positions. This improvement was partially offset by lower margins earned from cycling gas earned in a less volatile natural gas market and increased storage demand fees incurred to support our asset optimization activities.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $5.1 million. The increase reflects $2.4 million for the settlement of transaction and other tax matters coupled with a $2.3 million increase in employee and other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The reconciliation below of the economic gross profit, combined with the effect of unrealized gains or losses recognized in accordance with generally accepted accounting principles in the financial statements in prior periods, is presented to provide a measure of the potential gross profit from asset optimization that could occur in future periods if AEM's optimization efforts are executed as planned. We consider this measure of potential gross profit a non-GAAP financial measure as it is calculated using both forward-looking and historical financial information. The following table presents AEM's economic gross profit and its potential gross profit at December 31, 2007 and September 30, 2007.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gain	Potential Gross Profit
	(Bcf)	(In millions)	(In millions)	(In millions)
December 31, 2007	17.7	$44.2	$32.9	$11.3
September 30, 2007.	12.3	$40.8	$10.8	$30.0

As of December 31, 2007, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $44.2 million. This amount is reduced by $32.9 million of net unrealized gains recorded in the financial statements as of December 31, 2007 that will reverse when the inventory is withdrawn and the accompanying financial derivatives are settled. Therefore, the potential gross profit was $11.3 million. This potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses and increased income taxes to realize this amount.

The $18.7 million decrease in potential gross profit reflects a $22.1 million increase in unrealized gains attributable to a narrowing of the physical/financial spreads during the quarter. This decrease in potential gross profit was partially offset by a $3.4 million increase in the economic gross profit. During the quarter, natural gas fundamentals were bearish as a result of high inventory levels and warm weather. Therefore, AEM elected to increase its net physical position and execute forward sales contracts at positive spreads. Additionally, AEM elected to modify its original withdrawal schedule to meet its delivery schedule by buying more flowing gas and rolling financial positions to forward months to capture more favorable spreads.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled 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 December 31, 2007 will be fully realized in the future nor can we predict in what time periods such realization will 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 December 31, 2007, without encountering operational or other issues, we anticipate the majority of the potential gross profit as of December 31, 2007 will be recognized during the second quarter of fiscal 2008.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are each wholly-owned by Atmos Energy Holdings, Inc.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods. Additionally, beginning in fiscal 2006, APS initiated activities in the natural gas gathering business. As of December 31, 2007, these activities were limited in nature.

AES, through December 31, 2006, provided natural gas management services to our natural gas distribution operations, other than the Mid-Tex Division. These services included aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our natural gas distribution service areas at competitive prices. Effective January 1, 2007, these activities were moved to our shared services function included in our natural gas distribution segment. AES continues to provide limited services to our natural gas distribution divisions, and the revenues AES receives are equal to the costs incurred to provide those services.

Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and lease these plants through lease agreements that are accounted for as sales under generally accepted accounting principles.

Results for this segment are primarily impacted 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 December 31, 2007 and 2006 are presented below.

	Three Months Ended December 31		
	2007	2006	Change
	(In thousands)		
Storage and transportation services	$3,317	$ 4,064	$ (747)
Asset optimization	(958)	(535)	(423)
Other	1,266	1,359	(93)
Unrealized margins	2,373	6,220	(3,847)
Gross profit	5,998	11,108	(5,110)
Operating expenses	2,031	2,440	(409)
Operating income	3,967	8,668	(4,701)
Miscellaneous income	2,028	900	1,128
Interest charges	699	1,601	(902)
Income before income taxes	5,296	7,967	(2,671)
Income tax expense	2,104	3,138	(1,034)
Net income	$3,192	$ 4,829	$(1,637)

Pipeline, storage and other gross profit decreased $5.1 million primarily due to a $3.8 million decrease in unrealized margins associated with asset optimization activities. The change in gross profit also reflects a decrease of $0.5 million due to the transfer of gas supply operations from the pipeline, storage and other segment to our natural gas distribution segment effective January 1, 2007.

Operating expenses decreased $0.4 million primarily due to the decrease in employee and other administrative costs associated with the transfer of gas supply operations to our natural gas distribution segment.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program. Additionally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

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, 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 three months ended December 31, 2007, we generated operating cash flow of $61.4 million from operating activities compared with $165.0 million for the three months ended December 31, 2006. Quarter-over-quarter, our operating cash flow was unfavorably impacted by the utilization of lower income tax receivable balances coupled with the unfavorable timing of payments for various working capital items. Specifically, changes in other current assets, accounts payable, accrued liabilities and other current liabilities reduced operating cash flow by $97.3 million. Changes in cash required to collateralize our risk management accounts also reduced operating cash flow by $35.6 million. These decreases were partially offset by favorable timing of gas cost recoveries which increased operating cash flow by $16.2 million. Finally, other changes in working capital and other items increased operating cash flow by $13.1 million, primarily resulting from favorable net changes associated with our risk management activities.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund acquisitions and growth projects, our ongoing construction program and improvements to information 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, 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 2008 are expected to range from $450 million to $465 million. For the three months ended December 31, 2007, we incurred $94.2 million for capital expenditures compared with $87.0 million for the three months ended December 31, 2006. The increase in capital spending primarily reflects spending in the natural gas distribution segment for our new automated metering initiative. This initiative involves the installation of equipment that automatically reads and transfers customer consumption and other data to our customer information systems. This initiative is expected to improve the efficiency of our meter reading process.

Cash flows from financing activities

For the three months ended December 31, 2007, our financing activities provided $25.7 million compared with a use of cash of $58.1 million from financing activities in the prior-year period. Our significant financing activities for the three months ended December 31, 2007 and 2006 are summarized as follows.

- During the three months ended December 31, 2007, we increased our borrowings under our credit facilities by $50.7 million. The increase reflects borrowings to fund natural gas purchases for our winter heating season.

- In December 2006, we sold 6.3 million shares of common stock, including the underwriters' exercise of their overallotment option of 0.8 million shares, generating net proceeds of approximately $192 million. The net proceeds from this issuance were used to reduce our short-term debt.
- During the three months ended December 31, 2007, we paid $29.2 million in cash dividends compared with $26.3 million for the three months ended December 31, 2006. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.32 per share during the three months ended December 31, 2006 to $0.325 per share during the three months ended December 31, 2007 combined with our December 2006 equity offering and new share issuances under our various equity plans.
- During the three months ended December 31, 2007, we issued 0.2 million shares of common stock under our various equity plans which generated net proceeds of $6.0 million. In addition, we granted 0.4 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the three months ended December 31, 2007 and 2006.

	Three Months Ended December 31	
	2007	2006
Shares issued:		
Direct Stock Purchase Plan	95,891	80,701
Retirement Savings Plan	140,071	85,162
1998 Long-Term Incentive Plan	343,673	273,799
Outside Directors Stock-for-Fee Plan	817	669
Public Offering	—	6,325,000
Total shares issued	580,452	6,765,331

Credit Facilities

As of December 31, 2007, we had a total of approximately $1.5 billion of credit facilities, comprised of three short-term committed credit facilities totaling $918 million, one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. In January 2008, the unused portion of our $25 million uncommitted credit facility was terminated by the bank and the remaining balance will be terminated as the outstanding letters of credit expire. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

As of December 31, 2007, the amount available to us under our credit facilities, net of outstanding letters of credit, was $805.2 million. We believe these credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs. These facilities are described in further detail in Note 4 to the unaudited condensed financial statements.

Shelf Registration

On December 4, 2006, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in new common stock and/or debt securities available for issuance. As of December 31, 2007, we have approximately $450 million available for issuance under the registration statement. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the registration statement, we are permitted to issue a total of approximately $100 million of equity securities, $50 million of senior debt securities and $300 million of subordinated debt securities. In addition, due to restrictions imposed by another state regulatory commission, if the credit ratings on our senior unsecured debt were to fall below investment grade from either Standard & Poor's Corporation (BBB-), Moody's Investors Services, Inc. (Baa3) or Fitch Ratings, Ltd. (BBB-), our ability to issue any type of debt securities under the registration statement would be suspended until an investment grade rating from all three credit rating agencies was achieved.

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 utility and nonutility 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). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P maintains its positive outlook while Moody's and Fitch maintain their stable outlook. None of our ratings are currently under review.

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 December 31, 2007. Our debt covenants are described in Note 4 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization as of December 31, 2007 and September 30, 2007:

	December 31, 2007		September 30, 2007	
	(In thousands, except percentages)			
Short-term debt	$ 202,244	4.6%	$ 150,599	3.5%
Long-term debt	2,128,533	48.8%	2,130,146	50.2%
Shareholders' equity	2,032,483	46.6%	1,965,754	46.3%
Total capitalization, including short-term debt	$4,363,260	100.0%	$4,246,499	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 53.4 percent at December 31, 2007, and 53.7 percent at September 30, 2007. Our ratio of total debt to capitalization is typically greater during the winter heating season as we borrow 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 three months ended December 31, 2007.

Risk Management Activities

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, 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 fair value hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark-to-market instruments through earnings. In addition, natural gas inventory would be reflected on the balance sheet at the lower of cost or market instead of at fair value.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following tables show the components of the change in the fair value of our natural gas distribution and natural gas marketing commodity derivative contracts for the three months ended December 31, 2007 and 2006:

	Three Months Ended December 31, 2007		Three Months Ended December 31, 2006	
	Natural Gas Distribution	Natural Gas Marketing	Natural Gas Distribution	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period	$(21,053)	$26,808	$(27,209)	$15,003
Contracts realized/settled	(22,338)	5,075	(15,757)	45,899
Fair value of new contracts	(1,681)	—	(1,910)	—
Other changes in value	23,544	19,976	11,561	14,061
Fair value of contracts at end of period	$(21,528)	$51,859	$(33,315)	$74,963

The fair value of our natural gas distribution and natural gas marketing derivative contracts at December 31, 2007, is segregated below by time period and fair value source:

	Fair Value of Contracts at December 31, 2007				
	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	$24,833	$6,870	$—	$—	$31,703
Prices based on models and other valuation methods	(653)	(719)	—	—	(1,372)
Total Fair Value	$24,180	$6,151	$—	$—	$30,331

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2007 and 2006 our total net periodic pension and other benefits cost was $12.0 million and $12.1 million. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our total net periodic pension and other benefits cost remained flat during the current-year period when compared with the prior-year period as the assumptions we made during our annual pension plan valuation completed June 30, 2007 were consistent with the prior year. 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. At our June 30, 2007 measurement date, the interest rates were consistent with rates at our prior-year measurement date, which resulted in no change to our 6.30 percent discount rate used to determine our fiscal 2008 net periodic and post-retirement cost. In addition, our expected return on our pension plan assets remained constant at 8.25 percent.

During the three months ended December 31, 2007, we contributed $2.1 million to our other postretirement plans, and we expect to contribute a total of approximately $12 million to these plans during fiscal 2008.

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-month periods ended December 31, 2007 and 2006.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended December 31	
	2007	2006
METERS IN SERVICE, end of period		
Residential	2,925,426	2,915,864
Commercial	275,438	277,684
Industrial	2,319	3,023
Agricultural	10,962	8,626
Public authority and other	8,185	8,216
Total meters	3,222,330	3,213,413
INVENTORY STORAGE BALANCE — Bcf	60.0	60.3
HEATING DEGREE DAYS[1]		
Actual (weighted average)	1,081	1,135
Percent of normal	98%	101%
SALES VOLUMES — MMcf[2]		
Gas sales volumes		
Residential	49,031	50,699
Commercial	26,620	27,085
Industrial	5,954	5,735
Agricultural	550	110
Public authority and other	2,612	2,771
Total gas sales volumes	84,767	86,400
Transportation volumes	34,853	33,883
Total throughput	119,620	120,283
OPERATING REVENUES (000's)[2]		
Gas sales revenues		
Residential	$ 554,289	$ 574,736
Commercial	268,469	283,033
Industrial	51,176	53,983
Agricultural	4,983	575
Public authority and other	25,621	27,169
Total gas sales revenues	904,538	939,496
Transportation revenues	15,005	15,850
Other gas revenues	8,634	8,898
Total operating revenues	$ 928,177	$ 964,244
Average transportation revenue per Mcf	$ 0.43	$ 0.47
Average cost of gas per Mcf sold	$ 7.73	$ 8.12

See footnotes following these tables.

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

	Three Months Ended December 31	
	2007	2006
CUSTOMERS, end of period		
Industrial	735	700
Municipal	61	60
Other	469	420
Total	1,265	1,180
INVENTORY STORAGE BALANCE — Bcf		
Natural gas marketing	22.3	21.2
Pipeline, storage and other	2.6	2.7
Total	24.9	23.9
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	188,864	170,618
NATURAL GAS MARKETING SALES VOLUMES — MMcf(2)	108,709	88,038
OPERATING REVENUES (000's)(2)		
Regulated transmission and storage	$ 45,046	$ 39,872
Natural gas marketing	840,717	711,694
Pipeline, storage and other	6,727	11,333
Total operating revenues	$892,490	$762,899

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the year ended September 30, 2007. During the three months ended December 31, 2007, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

As indicated in the certifications in Exhibit 31 of this report, the Company's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as of December 31,

2007. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. In addition, there were no changes during the Company's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the three months ended December 31, 2007, 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 environmental-related matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the year ended September 30, 2007. 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 net 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.

SIGNATURES

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/ JOHN P. REDDY

John P. Reddy
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: February 6, 2008

EXHIBITS INDEX
Item 6(a)

Exhibit Number	Description	Page Number
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.