
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, 2005

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 an accelerated filer (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 29, 2005.

<u>Class</u>	<u>Shares Outstanding</u>
No Par Value	80,354,478

PART 1. FINANCIAL INFORMATION

Item 1. Financial Statements

**ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS**

	<u>June 30, 2005</u>	<u>September 30, 2004</u>
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	\$4,687,891	\$2,633,651
Less accumulated depreciation and amortization	<u>1,383,080</u>	<u>911,130</u>
Net property, plant and equipment	3,304,811	1,722,521
Current assets		
Cash and cash equivalents	23,637	201,932
Cash held on deposit in margin account	22,660	—
Accounts receivable, net	299,954	211,810
Gas stored underground	334,245	200,134
Other current assets	<u>75,958</u>	<u>63,236</u>
Total current assets	756,454	677,112
Goodwill and intangible assets	709,980	238,272
Deferred charges and other assets	<u>286,699</u>	<u>231,978</u>
	<u>\$5,057,944</u>	<u>\$2,869,883</u>
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, 2005 — 80,249,195 shares;		
September 30, 2004 — 62,799,710 shares	\$ 401	\$ 314
Additional paid-in capital	1,416,327	1,005,644
Retained earnings	220,569	142,030
Accumulated other comprehensive loss	<u>(21,287)</u>	<u>(14,529)</u>
Shareholders' equity	1,616,010	1,133,459
Long-term debt	<u>2,183,639</u>	<u>861,311</u>
Total capitalization	3,799,649	1,994,770
Current liabilities		
Accounts payable and accrued liabilities	231,881	185,295
Other current liabilities	342,408	223,265
Current maturities of long-term debt	<u>3,242</u>	<u>5,908</u>
Total current liabilities	577,531	414,468
Deferred income taxes	222,699	213,930
Regulatory cost of removal obligation	254,988	103,579
Deferred credits and other liabilities	<u>203,077</u>	<u>143,136</u>
	<u>\$5,057,944</u>	<u>\$2,869,883</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2005	2004
	(Unaudited)	
	(In thousands, except per share data)	
Operating revenues		
Utility segment	\$501,735	\$256,252
Natural gas marketing segment	466,835	364,339
Pipeline and storage segment	36,524	5,357
Other nonutility segment	1,421	853
Intersegment eliminations	<u>(96,563)</u>	<u>(80,743)</u>
	909,952	546,058
Purchased gas cost		
Utility segment	326,502	163,093
Natural gas marketing segment	456,440	352,708
Pipeline and storage segment	(1,733)	3,150
Other nonutility segment	—	—
Intersegment eliminations	<u>(95,606)</u>	<u>(80,385)</u>
	<u>685,603</u>	<u>438,566</u>
Gross profit	224,349	107,492
Operating expenses		
Operation and maintenance	94,518	50,467
Depreciation and amortization	43,448	23,268
Taxes, other than income	46,915	12,297
Total operating expenses	<u>184,881</u>	<u>86,032</u>
Operating income	39,468	21,460
Miscellaneous income	1,524	2,187
Interest charges	<u>33,689</u>	<u>16,011</u>
Income before income taxes	7,303	7,636
Income tax expense	<u>2,817</u>	<u>2,871</u>
Net income	<u>\$ 4,486</u>	<u>\$ 4,765</u>
Basic net income per share	<u>\$ 0.06</u>	<u>\$ 0.09</u>
Diluted net income per share	<u>\$ 0.06</u>	<u>\$ 0.09</u>
Cash dividends per share	<u>\$ 0.310</u>	<u>\$ 0.305</u>
Weighted average shares outstanding:		
Basic	<u>79,683</u>	<u>52,220</u>
Diluted	<u>80,144</u>	<u>52,617</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2005	2004
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment	\$2,650,793	\$1,425,022
Natural gas marketing segment	1,473,527	1,255,386
Pipeline and storage segment	130,798	18,243
Other nonutility segment	4,058	2,249
Intersegment eliminations	<u>(290,477)</u>	<u>(273,741)</u>
	3,968,699	2,427,159
Purchased gas cost		
Utility segment	1,895,181	1,003,977
Natural gas marketing segment	1,425,128	1,214,395
Pipeline and storage segment	8,895	9,158
Other nonutility segment	—	—
Intersegment eliminations	<u>(287,889)</u>	<u>(273,042)</u>
	3,041,315	1,954,488
Gross profit	927,384	472,671
Operating expenses		
Operation and maintenance	313,753	166,476
Depreciation and amortization	132,771	69,879
Taxes, other than income	<u>140,537</u>	<u>45,901</u>
Total operating expenses	<u>587,061</u>	<u>282,256</u>
Operating income	340,323	190,415
Miscellaneous income	2,867	7,850
Interest charges	<u>99,304</u>	<u>49,506</u>
Income before income taxes	243,886	148,759
Income tax expense	<u>91,299</u>	<u>56,148</u>
Net income	<u>\$ 152,587</u>	<u>\$ 92,611</u>
Basic net income per share	<u>\$ 1.96</u>	<u>\$ 1.79</u>
Diluted net income per share	<u>\$ 1.94</u>	<u>\$ 1.78</u>
Cash dividends per share	<u>\$ 0.930</u>	<u>\$ 0.915</u>
Weighted average shares outstanding:		
Basic	<u>78,009</u>	<u>51,788</u>
Diluted	<u>78,478</u>	<u>52,166</u>

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2005	2004
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	\$ 152,587	\$ 92,611
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on the sale of assets	—	(6,700)
Depreciation and amortization:		
Charged to depreciation and amortization	132,771	69,879
Charged to other accounts	634	1,270
Deferred income taxes	17,703	5,750
Other	7,593	(1,405)
Net assets/liabilities from risk management activities	14,276	4,469
Net change in operating assets and liabilities	61,846	193,388
Net cash provided by operating activities	387,410	359,262
Cash Flows From Investing Activities		
Capital expenditures	(226,851)	(129,508)
Acquisitions	(1,916,654)	(1,957)
Proceeds from the sale of assets	—	27,919
Other	(1,648)	(505)
Net cash used in investing activities	(2,145,153)	(104,051)
Cash Flows From Financing Activities		
Net decrease in short-term debt	—	(118,595)
Net proceeds from issuance of long-term debt	1,385,847	5,000
Repayment of long-term debt	(102,801)	(9,079)
Settlement of Treasury lock agreements	(43,770)	—
Cash dividends paid	(74,048)	(47,615)
Issuance of common stock	32,206	26,290
Net proceeds from equity offering	382,014	—
Net cash provided by (used in) financing activities	1,579,448	(143,999)
Net increase (decrease) in cash and cash equivalents	(178,295)	111,212
Cash and cash equivalents at beginning of period	201,932	15,683
Cash and cash equivalents at end of period	\$ 23,637	\$ 126,895

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2005

1. Nature of Business

Atmos Energy Corporation (“Atmos” or “the Company”) and its subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. Through our natural gas utility business, we distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public-authority and industrial customers through our seven regulated natural gas utility divisions, in the service areas described below:

<u>Division</u>	<u>Service Area</u>
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri ⁽³⁾
Atmos Energy Kentucky Division	Kentucky
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-States Division	Georgia ⁽³⁾ , Illinois ⁽³⁾ , Iowa ⁽³⁾ , Missouri ⁽³⁾ , Tennessee, Virginia ⁽³⁾
Atmos Energy Mississippi Division ⁽¹⁾	Mississippi
Atmos Energy Mid-Tex Division ⁽²⁾	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy West Texas Division	West Texas

⁽¹⁾ The name of this division was changed from the Mississippi Valley Gas Company Division in April 2005.

⁽²⁾ Acquired in October 2004.

⁽³⁾ Denotes locations where we have more limited service areas.

As further described in Note 3, on October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, storage, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. We also acquired a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas. As a result of the TXU Gas acquisition, on October 1, 2004, we created the Atmos Energy Mid-Tex Division, which provides gas distribution services to our approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. We also created the Atmos Pipeline — Texas Division to manage and operate the TXU Gas pipeline and storage operations we acquired.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared-services division is located in Dallas, Texas, and our customer support centers are located in Amarillo, Texas, and Metairie, Louisiana. In addition, on April 1, 2005, we took over the operations of a Waco, Texas customer support center, and all call center services formerly provided by TXU Gas under a transitional services agreement were terminated. We intend to close the purchase of the related assets on October 1, 2005 for approximately \$1.7 million.

Our nonutility businesses include our natural gas marketing operations, our pipeline and storage operations and our other nonutility operations which are provided in 22 states. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company.

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

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

and to our Colorado-Kansas, Kentucky, Louisiana and Mid-States 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 and storage operations consist of the operations of our Atmos Pipeline — Texas Division, a division of Atmos Energy Corporation, and of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division was purchased from TXU Gas and transports natural gas to the Atmos Energy Mid-Tex Division, transports natural gas to third parties and manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES) and Atmos Power Systems, Inc., which are wholly-owned by AEH. Through AES, we provide natural gas management services to our utility operations. These services, which began on April 1, 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Through Atmos Power Systems, Inc., we construct gas-fired electric peaking power-generating plants and associated facilities and may enter into agreements to either lease or sell these plants.

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 and notes 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 in its Annual Report on Form 10-K for the fiscal year ended September 30, 2004. Because of seasonal and other factors, the results of operations for the three and nine-month periods ended June 30, 2005 are not indicative of expected results of operations for the fiscal year ending September 30, 2005. Further, the impact of the TXU Gas acquisition on the statement of cash flows is reflected in the acquisitions line item; therefore, the net changes in operating assets and liabilities will not reflect balance sheet changes attributable solely to that acquisition.

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, 2004. There were no significant changes to our accounting policies during the nine months ended June 30, 2005.

Stock-based compensation plans

We have two stock-based compensation plans that provide for the granting of incentive stock options, nonqualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock and performance-based restricted stock units to officers and key employees: the 1998 Long-Term Incentive Plan and the Long-Term Stock Plan for the Mid-States Division. Nonemployee directors are also eligible to receive such stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of these plans include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As permitted by Statement of Financial Accounting Standards (SFAS) 123, *Accounting for Stock-Based Compensation*, we account for these plans under the intrinsic-value method described in Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees*. Under this method, no compensation cost for stock options is recognized for stock-option awards granted at or above fair-market value. Awards of restricted stock are valued at the market price of the Company's common stock on the date of grant. The unearned compensation is amortized to operation and maintenance expense over the vesting period of the restricted stock. As discussed below, beginning October 1, 2005 we will account for our stock-based compensation in accordance with SFAS 123 (revised), *Share-Based Payment*.

Had compensation expense for our stock options issued under the Long-Term Incentive Plan been recognized based on the fair value on the grant date under the methodology prescribed by SFAS 123, our net income and earnings per share for the three and nine-months ended June 30, 2005 and 2004 would have been impacted as shown in the following table:

	<u>Three Months Ended</u> <u>June 30</u>		<u>Nine Months Ended</u> <u>June 30</u>	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
	(In thousands, except per share amounts)			
Net income — as reported	\$4,486	\$4,765	\$152,587	\$92,611
Restricted stock compensation expense included in income, net of tax	542	384	1,514	580
Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax	<u>(676)</u>	<u>(651)</u>	<u>(2,114)</u>	<u>(1,428)</u>
Net income — pro forma	<u>\$4,352</u>	<u>\$4,498</u>	<u>\$151,987</u>	<u>\$91,763</u>
Earnings per share:				
Basic earnings per share — as reported	<u>\$ 0.06</u>	<u>\$ 0.09</u>	<u>\$ 1.96</u>	<u>\$ 1.79</u>
Basic earnings per share — pro forma	<u>\$ 0.05</u>	<u>\$ 0.09</u>	<u>\$ 1.95</u>	<u>\$ 1.77</u>
Diluted earnings per share — as reported	<u>\$ 0.06</u>	<u>\$ 0.09</u>	<u>\$ 1.94</u>	<u>\$ 1.78</u>
Diluted earnings per share — pro forma	<u>\$ 0.05</u>	<u>\$ 0.09</u>	<u>\$ 1.94</u>	<u>\$ 1.76</u>

At June 30, 2005, there were 300 options outstanding under the Long-Term Stock Plan for the Mid-States Division, all of which were fully vested. Because of the limited activities of this plan, the pro forma effects of applying SFAS 123 would have less than a \$0.01 per diluted share effect on earnings per share.

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 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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Significant regulatory assets and liabilities as of June 30, 2005 and September 30, 2004 included the following:

	June 30, 2005	September 30, 2004
	(In thousands)	
Regulatory assets:		
UCG merger and integration costs, net ⁽¹⁾	\$ —	\$ 1,992
Other merger and integration costs, net	12,034	14,644
Deferred MVG operating expenses	—	751
Environmental costs	1,834	3,104
Rate case costs	11,582	537
Deferred franchise fees	8,250	—
Other	7,257	3,705
	\$ 40,957	\$ 24,733
Regulatory liabilities:		
Deferred gas costs	\$ 44,906	\$ 39,097
Regulatory cost of removal obligation	266,553	111,232
Deferred income taxes, net	1,962	1,962
Other	3,325	—
	\$316,746	\$152,291

⁽¹⁾ Fully amortized as of December 2004.

Currently authorized rates do not include a return on our merger and integration costs; however, we recover the amortization of these costs through our rates. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Certain environmental costs have been deferred to future rate filings in accordance with rulings received from various regulatory commissions.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three and nine-month periods ended June 30, 2005 and 2004:

	Three Months Ended June 30		Nine Months Ended June 30	
	2005	2004	2005	2004
	(In thousands)			
Net income	\$ 4,486	\$ 4,765	\$152,587	\$92,611
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of \$(7) and \$(270) for the three months ended June 30, 2005 and 2004 and of \$722 and \$654 for the nine months ended June 30, 2005 and 2004	(11)	(441)	1,178	1,067
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of \$(2,675) and \$829 for the three months ended June 30, 2005 and 2004 and of \$(2,672) and \$829 for the nine months ended June 30, 2005 and 2004	(4,366)	1,353	(4,361)	1,353
Net unrealized gains (losses) and reclassification of unrealized losses into earnings on interest rate hedging transactions, net of tax expense (benefit) of \$528 and \$(2,684) for the three months ended June 30, 2005 and 2004 and of \$(2,190) and \$(2,684) for the nine months ended June 30, 2005 and 2004	<u>860</u>	<u>(4,377)</u>	<u>(3,575)</u>	<u>(4,377)</u>
Comprehensive income	<u>\$ 969</u>	<u>\$ 1,300</u>	<u>\$145,829</u>	<u>\$90,654</u>

Accumulated other comprehensive loss, net of tax, as of June 30, 2005 and September 30, 2004 consisted of the following unrealized gains (losses):

	June 30, 2005	September 30, 2004
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains (losses) on investments	\$ 334	\$ (844)
Treasury lock agreements	(24,843)	(21,268)
Cash flow hedges	<u>3,222</u>	<u>7,583</u>
	<u>\$ (21,287)</u>	<u>\$ (14,529)</u>

Recent accounting pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123 (revised), *Share-Based Payment* (SFAS 123 (R)). This standard revises SFAS 123, *Accounting for Stock-Based Compensation* and supersedes APB Opinion 25, *Accounting for Stock Issued to Employees*. Under SFAS 123 (R), public companies will be required to measure the cost of employee services received in exchange for stock options and similar awards based on the grant-date fair value of the award and recognize this cost in the income statement over the period during which an employee is required to provide service in exchange for the award. In April 2005, the Securities and Exchange Commission (SEC) deferred the

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

required effective date of SFAS 123 (R) until the beginning of a registrant's next fiscal year. Accordingly, SFAS 123 (R) will become effective for the Company for fiscal 2006 beginning on October 1, 2005.

We will adopt SFAS 123 (R) as of October 1, 2005 using the modified prospective method. Under this method, we will recognize compensation cost, on a prospective basis, for the portion of outstanding awards for which the requisite service has not yet been rendered as of October 1, 2005, based upon the grant-date fair value of those awards calculated under SFAS 123 for pro forma disclosure purposes. We expect that the adoption of SFAS 123 (R) will reduce our fiscal 2006 net income by approximately \$0.5 million.

3. TXU Gas Acquisition

On October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company. The purchase was accounted for as an asset purchase. The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, storage, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. Through these newly acquired operations, we provide gas distribution services to approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. We also now own and operate a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs in Texas.

The purchase price for the TXU Gas acquisition was approximately \$1.9 billion (after closing adjustments and before transaction costs and expenses), which we paid in cash. We acquired approximately \$112 million of working capital of TXU Gas after the final working capital and capital expenditures settlement was negotiated during the third quarter of 2005, which resulted in a net payment to TXU Corporation of approximately \$4.1 million. We did not assume any indebtedness of TXU Gas in connection with the acquisition. TXU Gas retained certain assets, provided for the repayment of all of its indebtedness and redeemed all of its preferred stock prior to closing and retained and agreed to pay certain other liabilities under the terms of the acquisition agreement.

We funded the purchase price for the TXU Gas acquisition with approximately \$235.7 million in net proceeds from our offering of approximately 9.9 million shares of common stock, which we completed on July 19, 2004, and approximately \$1.7 billion in net proceeds from our issuance on October 1, 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 to provide bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes on October 22, 2004, which generated net proceeds of approximately \$1.39 billion, and the sale of 16.1 million shares of common stock on October 27, 2004, which generated net proceeds of \$382.0 million.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the fair values of the assets acquired and liabilities assumed on October 1, 2004 (in thousands):

Cash purchase price	\$1,908,999
Transaction costs and expenses	<u>7,655</u>
Total purchase price	<u>\$1,916,654</u>
Net property, plant and equipment	\$1,471,643
Accounts receivable	62,212
Gas stored underground	138,818
Other current assets	21,743
Goodwill	472,215
Deferred charges and other assets	42,069
Deferred income taxes	4,794
Accounts payable and accrued liabilities	(21,799)
Other current liabilities	(70,087)
Regulatory cost of removal obligation	(138,991)
Deferred credits and other liabilities	<u>(65,963)</u>
Total	<u>\$1,916,654</u>

The sale of TXU Gas's assets was held through a competitive bid process. We believe the resulting goodwill is recoverable given the expected synergies we can achieve as a result of the TXU Gas acquisition. To that end, the TXU Gas acquisition significantly expands our existing utility operations in Texas. The North Texas operations of TXU Gas bridge our geographic operations between our existing utility operations in West Texas and Louisiana. TXU Gas's headquarters and service area are centered in Dallas, Texas, which is also the location of our corporate headquarters. Further, the addition of the regulated pipelines and storage operations in North Texas may create additional gas marketing and other opportunities for our non-regulated subsidiaries, which include gas marketing and storage operations. The goodwill generated in the acquisition is deductible for tax purposes.

Our allocation of the purchase price is preliminary and is subject to change due to our continuing review of the acquired assets and liabilities. The amount currently allocated to property, plant and equipment represents our estimate of the fair value of the assets acquired. We have based that estimate on the amount we believe will ultimately be approved as rate base for rate setting purposes.

The table below reflects the unaudited pro forma results of the Company and TXU Gas for the three and nine-month periods ended June 30, 2004 as if the acquisition and related financing had taken place at the beginning of fiscal 2004:

	<u>Three Months Ended</u> <u>June 30, 2004</u>	<u>Nine Months Ended</u> <u>June 30, 2004</u>
	(In thousands, except per share data)	
Operating revenue	\$761,578	\$3,496,156
Net income (loss)	(2,161)	132,988
Net income (loss) per diluted share	\$ (0.03)	\$ 1.70

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

4. Goodwill and Intangible Assets

Goodwill and intangible assets are comprised of the following as of June 30, 2005 and September 30, 2004.

	June 30, 2005	September 30, 2004
(In thousands)		
Goodwill	\$706,327	\$234,112
Intangible assets	3,653	4,160
Total	\$709,980	\$238,272

The following presents our goodwill balance allocated by segment and changes in our balance for the nine months ended June 30, 2005:

	Utility Segment	Natural Gas Marketing Segment	Pipeline and Storage Segment	Other Non-utility Segment	Total
(In thousands)					
Balance as of September 30, 2004	\$199,400	\$24,282	\$ —	\$ 10,430	\$234,112
Intersegment transfer of assets ⁽¹⁾	—	—	10,430	(10,430)	—
TXU Gas acquisition (Note 3)	351,969	—	120,246	—	472,215
Balance as of June 30, 2005	\$551,369	\$24,282	\$130,676	\$ —	\$706,327

⁽¹⁾ Effective October 1, 2004, we created the pipeline and storage segment which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division as well as the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC, previously included in our other nonutility segment. Accordingly, goodwill allocable to Atmos Pipeline and Storage, LLC was transferred to the pipeline and storage segment.

During the second quarter of fiscal 2005, we completed our annual goodwill impairment assessment. Based upon the assessment performed, we determined our goodwill was not impaired.

5. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility 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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table shows the fair values of our risk management assets and liabilities by segment at June 30, 2005 and September 30, 2004:

	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Total</u>
		(In thousands)	
June 30, 2005:			
Assets from risk management activities, current	\$ 25,456	\$ 3,347	\$ 28,803
Assets from risk management activities, noncurrent	—	—	—
Liabilities from risk management activities, current	—	(8,558)	(8,558)
Liabilities from risk management activities, noncurrent	—	(2,844)	(2,844)
Net assets (liabilities)	<u>\$ 25,456</u>	<u>\$(8,055)</u>	<u>\$ 17,401</u>
September 30, 2004:			
Assets from risk management activities, current	\$ 25,692	\$18,748	\$ 44,440
Assets from risk management activities, noncurrent	—	562	562
Liabilities from risk management activities, current	(34,304)	(5,154)	(39,458)
Liabilities from risk management activities, noncurrent	—	(1,138)	(1,138)
Net assets (liabilities)	<u>\$ (8,612)</u>	<u>\$13,018</u>	<u>\$ 4,406</u>

Utility Hedging Activities

We use a combination of 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 utility segment ultimately will be 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 to our utility segment as a result of the use of financial derivatives. For the 2004-2005 heating season, we hedged approximately 59 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately \$6.23 per Mcf. Our utility hedging activities also include the cost of our Treasury lock agreements which are described in further detail below.

Nonutility Hedging Activities

AEM manages its exposure to the risk of natural gas price changes through a combination of 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.

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales and ceased marking these contracts to market. As a result, unrealized gains and losses on open derivative contracts which are used to hedge price risk associated with these fixed-price forward contracts are now designated as cash flow hedges and recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold.

For the three and nine-month periods ended June 30, 2005, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, and the recognition for the nine months ended June 30, 2005 of \$9.3 million in net deferred hedging gains (\$5.1 million during the three months ended June 30, 2005) in net income when the derivative contracts matured according to their terms. The net

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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. Substantially all of the deferred hedging balance as of June 30, 2005 is expected to be recognized in net income in fiscal 2006 and beyond.

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 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 June 30, 2005, AEH had a net open position (including existing storage) of 0.2 Bcf.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of \$875 million of long-term debt subsequent to September 30, 2004. This long-term debt was issued on October 22, 2004 and was used to repay a portion of the commercial paper used to fund the TXU Gas acquisition, as described in Note 3. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. These Treasury lock agreements were settled in October 2004 with a net \$43.8 million payment to the counterparties. This amount will remain in accumulated other comprehensive income and will be recognized as a component of interest expense over the next ten years. During the three and nine-month periods ended June 30, 2005, we recognized approximately \$1.4 million and \$3.7 million of this obligation as a component of interest expense.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

6. Debt

Long-Term Debt

Long-term debt at June 30, 2005 and September 30, 2004 consisted of the following:

	<u>June 30, 2005</u>	<u>September 30, 2004</u>
(In thousands)		
Unsecured floating rate Senior Notes, due 2007	\$ 300,000	\$ —
Unsecured 4.00% Senior Notes, due 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	—
Unsecured 5.95% Senior Notes, due 2034	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 J, 9.40% due 2021	—	17,000
Series P, 10.43% due 2013	10,000	11,250
Series Q, 9.75% due 2020	—	16,000
Series T, 9.32% due 2021	—	18,000
Series U, 8.77% due 2022	—	20,000
Series V, 7.50% due 2007	—	4,167
Other term notes due in installments through 2013	<u>8,463</u>	<u>9,830</u>
Total long-term debt	2,190,766	868,550
Less:		
Original issue discount on unsecured senior notes and debentures ..	(3,885)	(1,331)
Current maturities	<u>(3,242)</u>	<u>(5,908)</u>
	<u>\$2,183,639</u>	<u>\$861,311</u>

Our unsecured floating rate debt bears interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At June 30, 2005, the interest rate on our floating rate debt was 3.516 percent.

On June 30, 2005, we elected to utilize excess cash to repay \$72.5 million in principal on five series of our First Mortgage Bonds prior to their scheduled maturity. In connection with the repayment, we paid a \$25.0 million make-whole premium in accordance with the terms of the agreements and accrued interest of approximately \$1.0 million. In accordance with regulatory requirements, the premium has been deferred and will be recognized over the remaining original lives of the First Mortgage Bonds that were repaid.

Short-Term Debt

At June 30, 2005 and September 30, 2004, there were no short-term amounts outstanding under our commercial paper program or bank credit facilities.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 bank. 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.

Committed Credit Facilities

As of June 30, 2005, we had two short-term committed revolving credit facilities totaling \$618.0 million, one of which is an unsecured facility for \$600.0 million that bears interest at the Eurodollar rate plus 0.625 percent and serves as a backup liquidity facility for our \$600.0 million commercial paper program. We entered into this facility on October 22, 2004 to replace our \$350.0 million credit facility that served as the backup liquidity facility for our \$350.0 million commercial paper program. At June 30, 2005, no commercial paper was outstanding.

We have a second unsecured facility in place for \$18.0 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired on March 31, 2005 and was renewed effective April 1, 2005 with no material changes to its terms and pricing. There were no borrowings under this facility at June 30, 2005.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently meet. 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 \$600.0 million credit facility 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, 2005, our total-debt-to-total-capitalization ratio, as defined, was 60 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our \$600.0 million credit facility are subject to adjustment depending upon our credit ratings.

Uncommitted Credit Facilities

AEM had a \$250.0 million uncommitted demand working capital credit facility that bore interest at the Eurodollar rate plus 2.5 percent that was scheduled to expire on March 31, 2005. On March 30, 2005, the facility was amended and extended to March 31, 2006. This facility is guaranteed by AEH.

Borrowings under the amended 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 0.50% per annum above the Federal Funds rate or the lender's prime rate) plus 0.50%. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR plus an applicable margin, ranging from 1.375% to 1.75% 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 1.125% to 2.00% 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 to maintain 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 \$50 million. Additionally, AEM must maintain a minimum tangible net worth ranging from \$21 million to \$51 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding \$4 million to \$10 million, depending on the total amount of borrowing elected from time to time by AEM. At June 30, 2005, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.14 to 1.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At June 30, 2005, no amounts were outstanding under this credit facility. However, at June 30, 2005, AEM letters of credit totaling \$81.2 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 \$68.8 million at June 30, 2005. 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 for \$25.0 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at June 30, 2005, but letters of credit reduced the amount available by \$4.2 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when- and as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a \$100.0 million intercompany uncommitted demand credit facility with the Company which bears interest at LIBOR plus 2.75%. This facility has been approved by our state regulators through December 31, 2005. At June 30, 2005, there was no amount outstanding under this facility.

In addition, AEM has a \$100.0 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at the LIBOR rate plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's \$250.0 million uncommitted demand credit facility described above. This facility is used to supplement AEM's \$250.0 million credit facility. At June 30, 2005, there was \$53.0 million outstanding under this facility. On July 1, 2005, this facility was renewed and the amount available for borrowing was increased to \$120.0 million.

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, after November 2007, 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 \$9.0 million. At June 30, 2005 approximately \$199.6 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 June 30, 2005. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our \$600.0 million revolving credit agreement, 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 is 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.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

7. Equity

On February 9, 2005, our shareholders approved an amendment to our Articles of Incorporation to increase the number of authorized shares from 100 million to 200 million.

On October 27, 2004, we completed the public offering of 16.1 million shares of our common stock including the underwriters' exercise of their overallotment option of 2.1 million shares. The offering was priced at \$24.75 and generated net proceeds of approximately \$382.0 million. We used the net proceeds from this offering, together with net proceeds of \$235.7 million from a public offering we conducted in July 2004 and \$1.39 billion received from the issuance of senior unsecured notes to pay off the \$1.7 billion in outstanding commercial paper described in Note 3 and fund the remainder of the purchase price for the TXU Gas acquisition.

8. Earnings Per Share

Basic and diluted earnings per share at June 30 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2005	2004	2005	2004
	(In thousands, except per share amounts)			
Net income	\$ 4,486	\$ 4,765	\$152,587	\$92,611
Denominator for basic income per share — weighted average common shares	79,683	52,220	78,009	51,788
Effect of dilutive securities:				
Restricted and other shares	330	258	325	258
Stock options	131	139	144	120
Denominator for diluted income per share — weighted average common shares	80,144	52,617	78,478	52,166
Income per share — basic	\$ 0.06	\$ 0.09	\$ 1.96	\$ 1.79
Income per share — diluted	\$ 0.06	\$ 0.09	\$ 1.94	\$ 1.78

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended June 30, 2005 and 2004 as their exercise price was less than the average market price of the common stock during that period.

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the nine months ended June 30, 2005. There were 3,000 out-of-the-money options excluded from the computation of diluted earnings per share for the nine months ended June 30, 2004 as their exercise price was greater than the average market price of the common stock during that period.

9. Interim Pension and Other Post Retirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other post-retirement benefit plans for the three months ended June 30, 2005 and 2004 are presented in the following table. All of these costs are

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	<u>Three Months Ended June 30</u>			
	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
	(In thousands)			
Components of net periodic pension cost:				
Service cost	\$ 3,136	\$ 2,433	\$2,478	\$1,405
Interest cost	6,017	6,004	2,366	1,751
Expected return on assets	(6,885)	(7,524)	(518)	(396)
Amortization of transition asset	1	24	378	378
Amortization of prior service cost	(2)	(2)	96	96
Amortization of actuarial loss	<u>1,891</u>	<u>2,018</u>	<u>151</u>	<u>—</u>
Net periodic pension cost	<u>\$ 4,158</u>	<u>\$ 2,953</u>	<u>\$4,951</u>	<u>\$3,234</u>

The components of our net periodic pension cost for our pension and other post-retirement benefit plans for the nine months ended June 30, 2005 and 2004 are as follows:

	<u>Nine Months Ended June 30</u>			
	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
	(In thousands)			
Components of net periodic pension cost:				
Service cost	\$ 9,408	\$ 7,299	\$ 7,434	\$ 4,535
Interest cost	18,051	18,012	7,098	5,605
Expected return on assets	(20,655)	(22,572)	(1,554)	(1,127)
Amortization of transition asset	3	72	1,134	1,134
Amortization of prior service cost	(6)	(6)	288	288
Amortization of actuarial loss	<u>5,673</u>	<u>6,054</u>	<u>453</u>	<u>635</u>
Net periodic pension cost	<u>\$ 12,474</u>	<u>\$ 8,859</u>	<u>\$14,853</u>	<u>\$11,070</u>

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2005 and 2004 are as follows:

	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
Discount rate	6.25%	6.00%	6.25%	6.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.75%	9.00%	5.30%	5.30%

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. In the period leading up to our June 30, 2005 measurement date, these interest rates were declining, which has the effect of increasing the present value of our plan liabilities. Accordingly, we voluntarily contributed in June 2005 \$3.0 million to our Pension Account Plan to maintain the level of funding we desire relative to our accumulated benefit obligation. We were not required to make a minimum funding contribution during fiscal 2005 nor do we anticipate making any additional voluntary contributions during the remainder of fiscal 2005.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

During the nine months ended June 30, 2005, we contributed \$7.0 million to our other post-retirement plans and we expect to contribute approximately \$11.7 million to these plans during fiscal 2005.

10. Commitments and Contingencies

Litigation and Environmental Matters

We are involved in litigation and environmental matters and claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental matters and 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 net cash flows.

As discussed in our Form 10-Q for the three months ended December 31, 2004, we were the plaintiff in a case styled *Energas Company, a Division of Atmos Energy Corporation v. ONEOK Energy Marketing and Trading Company, L.P., ONEOK Westex Transmission, Inc., and ONEOK Energy Marketing and Trading Company II*, filed in December 2001, in the 72nd Judicial District in the District Court of Lubbock County, Texas. This case was filed to recover damages resulting from various claims involving the sale, measurement, transportation and balancing of natural gas. This case and all related claims have been settled. The settlement did not have a material effect on our financial condition, results of operations or net cash flows.

During the nine months ended June 30, 2005, there were no other material changes in the status of the litigation and environmental matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2004. However, with the acquisition of the natural gas distribution and pipeline operations of TXU Gas Company on October 1, 2004, we assumed responsibility for certain litigation and claims that arose in the ordinary course of the business of TXU Gas Company. We believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or net 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, 2005, AEM was committed to purchase 46.4 Bcf within one year, 5.7 Bcf within one to three years and 1.1 Bcf after three years under indexed contracts. AEM is committed to purchase 0.7 Bcf within one year and 0.5 Bcf within one to three years under fixed price contracts with prices ranging from \$5.24 to \$7.68. Purchases under these contracts totaled \$294.0 million and \$283.5 million for the three months ended June 30, 2005 and 2004 and \$999.4 million and \$981.5 million for the nine months ended June 30, 2005 and 2004.

Our historical utility operations 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 commitments under these contracts as of June 30, 2005 are as follows (in thousands):

2005	\$ 84,604
2006	270,730
2007	58,367
2008	31,059
2009	11,519
Thereafter	<u>45,524</u>
	<u>\$501,803</u>

Other

In January 2005, we signed a letter of intent with a third party to jointly construct, own and operate a 45-mile large diameter natural gas pipeline in the northern portion of the Dallas/Fort Worth Metroplex. Under terms of the letter of intent, the third party will provide the initial capital to build the pipeline and we will contribute up to \$42.5 million within two years of signing of a definitive agreement. The pipeline is currently expected to be placed into service in fiscal 2006.

In May 2005, we entered into a five year agreement with a third party to transport up to 100,000 MMBtu per day of natural gas through our Texas intrastate pipeline system beginning in April 2006. To handle the increased volumes for this project and other planned projects, we will install compression equipment and other pipeline infrastructure, costing approximately \$20 million.

11. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the utility segment is mitigated by the large number of individual customers and diversity in customer base.

Customer diversification also helps mitigate AEM's credit exposure. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends and other information. We believe, based on our credit policies and our provisions for credit losses, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by the credit department, but are primarily

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

based on external ratings provided by Moody's Investor Service Inc. and/or Standard & Poor's. For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrial and commercial customers is non-investment grade. The table below shows the percentages related to the investment ratings as of June 30, 2005 and September 30, 2004.

	June 30, 2005	September 30, 2004
Investment grade	55%	55%
Non-investment grade	<u>45%</u>	<u>45%</u>
Total	<u>100%</u>	<u>100%</u>

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of June 30, 2005. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's; or Baa3, assigned by Moody's Investor Service. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	June 30, 2005		
Utility Segment⁽¹⁾	Natural Gas Marketing Segment	Consolidated	
	(In thousands)		
Investment grade counterparties	\$25,456	\$2,364	\$27,820
Non-investment grade counterparties	—	983	983
	<u>\$25,456</u>	<u>\$3,347</u>	<u>\$28,803</u>

⁽¹⁾ Counterparty risk for our utility segment is minimized because hedging gains and losses are passed through to our customers.

12. Segment Information

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

Through our nonutility businesses we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and sales operations,
- the natural gas marketing segment, which includes a variety of natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonutility operations.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Effective October 1, 2004, we created the pipeline and storage segment which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC, which was previously included in our other nonutility segment. Segment information for all prior year periods has been restated to reflect our new organizational structure.

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 utility segment operations are geographically dispersed, they are reported as a single segment as each utility 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, 2004. We evaluate performance based on net income or loss of the respective operating units.

Summarized income statements for the three and nine-month periods ended June 30, 2005 and 2004 by segment are presented in the following tables:

	Three Months Ended June 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	\$501,481	\$387,999	\$19,929	\$ 543	\$ —	\$909,952
Intersegment revenues	254	78,836	16,595	878	(96,563)	—
	501,735	466,835	36,524	1,421	(96,563)	909,952
Purchased gas cost	326,502	456,440	(1,733)	—	(95,606)	685,603
Gross profit	175,233	10,395	38,257	1,421	(957)	224,349
Operating expenses						
Operation and maintenance	76,862	4,948	12,648	1,067	(1,007)	94,518
Depreciation and amortization	38,775	458	4,189	26	—	43,448
Taxes, other than income	44,555	242	2,064	54	—	46,915
Total operating expenses	160,192	5,648	18,901	1,147	(1,007)	184,881
Operating income	15,041	4,747	19,356	274	50	39,468
Miscellaneous income	3,122	153	613	578	(2,942)	1,524
Interest charges	28,520	957	6,169	935	(2,892)	33,689
Income (loss) before income taxes ..	(10,357)	3,943	13,800	(83)	—	7,303
Income tax expense (benefit)	(3,689)	1,583	4,958	(35)	—	2,817
Net income (loss)	<u>\$ (6,668)</u>	<u>\$ 2,360</u>	<u>\$ 8,842</u>	<u>\$ (48)</u>	<u>\$ —</u>	<u>\$ 4,486</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Three Months Ended June 30, 2004					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	\$255,986	\$288,809	\$ 690	\$ 573	\$ —	\$546,058
Intersegment revenues	266	75,530	4,667	280	(80,743)	—
	256,252	364,339	5,357	853	(80,743)	546,058
Purchased gas cost	163,093	352,708	3,150	—	(80,385)	438,566
Gross profit	93,159	11,631	2,207	853	(358)	107,492
Operating expenses						
Operation and maintenance	45,974	3,767	669	415	(358)	50,467
Depreciation and amortization	22,435	513	292	28	—	23,268
Taxes, other than income	11,558	504	171	64	—	12,297
Total operating expenses	79,967	4,784	1,132	507	(358)	86,032
Operating income	13,192	6,847	1,075	346	—	21,460
Miscellaneous income	1,668	178	90	1,547	(1,296)	2,187
Interest charges	16,119	411	257	520	(1,296)	16,011
Income (loss) before income taxes	(1,259)	6,614	908	1,373	—	7,636
Income tax expense (benefit)	(711)	2,664	366	552	—	2,871
Net income (loss)	<u>\$ (548)</u>	<u>\$ 3,950</u>	<u>\$ 542</u>	<u>\$ 821</u>	<u>\$ —</u>	<u>\$ 4,765</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Nine Months Ended June 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	\$2,649,979	\$1,250,507	\$ 66,546	\$1,667	\$ —	\$3,968,699
Intersegment revenues	814	223,020	64,252	2,391	(290,477)	—
	2,650,793	1,473,527	130,798	4,058	(290,477)	3,968,699
Purchased gas cost	1,895,181	1,425,128	8,895	—	(287,889)	3,041,315
Gross profit	755,612	48,399	121,903	4,058	(2,588)	927,384
Operating expenses						
Operation and maintenance . . .	259,884	12,410	41,190	3,007	(2,738)	313,753
Depreciation and amortization . . .	119,007	1,436	12,244	84	—	132,771
Taxes, other than income	133,395	412	6,510	220	—	140,537
Total operating expenses	512,286	14,258	59,944	3,311	(2,738)	587,061
Operating income	243,326	34,141	61,959	747	150	340,323
Miscellaneous income	6,068	600	1,220	1,787	(6,808)	2,867
Interest charges	83,841	2,037	18,568	1,516	(6,658)	99,304
Income before income taxes	165,553	32,704	44,611	1,018	—	243,886
Income tax expense	61,547	13,291	16,047	414	—	91,299
Net income	<u>\$ 104,006</u>	<u>\$ 19,413</u>	<u>\$ 28,564</u>	<u>\$ 604</u>	<u>\$ —</u>	<u>\$ 152,587</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Nine Months Ended June 30, 2004					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	\$1,424,180	\$ 999,135	\$ 2,057	\$1,787	\$ —	\$2,427,159
Intersegment revenues	842	256,251	16,186	462	(273,741)	—
	1,425,022	1,255,386	18,243	2,249	(273,741)	2,427,159
Purchased gas cost	1,003,977	1,214,395	9,158	—	(273,042)	1,954,488
Gross profit	421,045	40,991	9,085	2,249	(699)	472,671
Operating expenses						
Operation and maintenance	152,089	11,751	1,945	1,390	(699)	166,476
Depreciation and amortization ..	67,072	1,579	1,140	88	—	69,879
Taxes, other than income	43,843	932	875	251	—	45,901
Total operating expenses	263,004	14,262	3,960	1,729	(699)	282,256
Operating income	158,041	26,729	5,125	520	—	190,415
Miscellaneous income	4,001	530	113	7,658	(4,452)	7,850
Interest charges	49,285	2,284	808	1,581	(4,452)	49,506
Income before income taxes	112,757	24,975	4,430	6,597	—	148,759
Income tax expense	41,636	10,067	1,786	2,659	—	56,148
Net income	<u>\$ 71,121</u>	<u>\$ 14,908</u>	<u>\$ 2,644</u>	<u>\$3,938</u>	<u>\$ —</u>	<u>\$ 92,611</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at June 30, 2005 and September 30, 2004 by segment is presented in the following tables:

	June 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	\$2,866,980	\$ 7,530	\$428,881	\$ 1,420	\$ —	\$3,304,811
Investment in subsidiaries . . .	208,520	(1,821)	—	—	(206,699)	—
Current assets						
Cash and cash equivalents	13,793	8,272	—	1,572	—	23,637
Cash held on deposit in margin account	—	22,660	—	—	—	22,660
Assets from risk management activities . .	25,456	4,708	459	—	(1,820)	28,803
Other current assets	385,413	280,745	50,346	56,824	(91,974)	681,354
Intercompany receivables . .	558,700	—	—	—	(558,700)	—
Total current assets	983,362	316,385	50,805	58,396	(652,494)	756,454
Intangible assets	—	3,653	—	—	—	3,653
Goodwill	551,369	24,282	130,676	—	—	706,327
Noncurrent assets from risk management activities						
Deferred charges and other assets	258,658	1,506	5,818	20,717	—	286,699
	<u>\$4,868,889</u>	<u>\$351,535</u>	<u>\$616,180</u>	<u>\$80,533</u>	<u>\$(859,193)</u>	<u>\$5,057,944</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,616,010	\$114,330	\$ 61,161	\$33,029	\$(208,520)	\$1,616,010
Long-term debt	<u>2,177,168</u>	—	—	<u>6,471</u>	—	<u>2,183,639</u>
Total capitalization	3,793,178	114,330	61,161	39,500	(208,520)	3,799,649
Current liabilities						
Current maturities of long-term debt	1,250	—	—	1,992	—	3,242
Short-term debt	—	53,000	—	—	(53,000)	—
Liabilities from risk management activities . .	—	9,428	1,361	—	(2,231)	8,558
Other current liabilities . . .	411,538	127,813	56,918	6,231	(36,769)	565,731
Intercompany payables	—	49,948	484,517	24,235	(558,700)	—
Total current liabilities . .	412,788	240,189	542,796	32,458	(650,700)	577,531
Deferred income taxes	219,001	(6,033)	7,727	1,977	27	222,699
Noncurrent liabilities from risk management activities						
Regulatory cost of removal obligation	254,988	—	—	—	—	254,988
Deferred credits and other liabilities	188,934	205	4,496	6,598	—	200,233
	<u>\$4,868,889</u>	<u>\$351,535</u>	<u>\$616,180</u>	<u>\$80,533</u>	<u>\$(859,193)</u>	<u>\$5,057,944</u>

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	September 30, 2004					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	\$1,669,304	\$ 7,875	\$43,784	\$ 1,558	\$ —	\$1,722,521
Investment in subsidiaries	164,300	(1,484)	—	—	(162,816)	—
Current assets						
Cash and cash equivalents ..	182,846	18,734	—	352	—	201,932
Assets from risk management activities ...	25,692	24,412	—	—	(5,664)	44,440
Other current assets	253,829	170,363	13,473	18,815	(25,740)	430,740
Intercompany receivables ...	1,995	—	—	16,079	(18,074)	—
Total current assets	464,362	213,509	13,473	35,246	(49,478)	677,112
Intangible assets	—	4,160	—	—	—	4,160
Goodwill	199,400	24,282	10,430	—	—	234,112
Noncurrent assets from risk management activities	—	734	—	—	(172)	562
Deferred charges and other assets	207,019	1,661	25	22,711	—	231,416
	<u>\$2,704,385</u>	<u>\$250,737</u>	<u>\$67,712</u>	<u>\$59,515</u>	<u>\$(212,466)</u>	<u>\$2,869,883</u>
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	\$1,133,459	\$103,376	\$28,499	\$32,425	\$(164,300)	\$1,133,459
Long-term debt	853,472	—	—	7,839	—	861,311
Total capitalization	1,986,931	103,376	28,499	40,264	(164,300)	1,994,770
Current liabilities						
Current maturities of long- term debt	3,917	—	—	1,991	—	5,908
Short-term debt	—	—	—	—	—	—
Liabilities from risk management activities ...	34,304	11,407	—	—	(6,253)	39,458
Other current liabilities	236,257	124,577	24,014	7,558	(23,304)	369,102
Intercompany payables	—	9,906	8,168	—	(18,074)	—
Total current liabilities ...	274,478	145,890	32,182	9,549	(47,631)	414,468
Deferred income taxes	208,325	(3,360)	6,961	1,977	27	213,930
Noncurrent liabilities from risk management activities	—	1,700	—	—	(562)	1,138
Regulatory cost of removal obligation	103,579	—	—	—	—	103,579
Deferred credits and other liabilities	131,072	3,131	70	7,725	—	141,998
	<u>\$2,704,385</u>	<u>\$250,737</u>	<u>\$67,712</u>	<u>\$59,515</u>	<u>\$(212,466)</u>	<u>\$2,869,883</u>

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, 2005, and the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2005 and 2004, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2005 and 2004. 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 interim 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, 2004, 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 9, 2004, 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, 2004, 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
August 5, 2005

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, 2004.

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 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 the Company 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 the Company's documents or oral presentations, the words "anticipate", "believe", "expect", "estimate", "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 the Company's strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: adverse weather conditions, such as warmer than normal weather in the Company's utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; 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 and counterparty creditworthiness; national, regional and local economic conditions; the Company's 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; increased competition from energy suppliers and alternative forms of energy; risks relating to the acquisition of the TXU Gas operations, including without limitation, the Company's increased indebtedness resulting from the acquisition and the successful integration of the TXU Gas operations; and other uncertainties, which may be discussed herein, all of which are difficult to predict and many of which are beyond the control of the Company. A more detailed discussion of these risks and uncertainties may be found in the Company's Form 10-K for the year ended September 30, 2004. Accordingly, while the Company believes 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, the Company undertakes no obligation to update or revise any of its forward-looking statements whether as a result of new information, future events or otherwise.

Overview

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

Through our nonutility businesses we provide natural gas management, transportation, storage and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and sales operations,
- the natural gas marketing segment, which includes a variety of natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonutility operations.

Fiscal 2005 has been highlighted by our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. Through these newly acquired operations, we provide gas distribution services to approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. We also now own and operate a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs in Texas. On April 1, 2005, we took over the operations of a Waco, Texas customer support center and all call center services formerly provided by TXU Gas under a transitional services agreement were terminated. We intend to close the purchase of the related assets on October 1, 2005 for approximately \$1.7 million.

The purchase price of the TXU Gas acquisition was approximately \$1.9 billion, before transaction costs and expenses, which we paid in cash. We funded the purchase price for the TXU Gas acquisition with approximately \$235.7 million in net proceeds from our offering of approximately 9.9 million shares of common stock, which we completed on July 19, 2004, and approximately \$1.7 billion in net proceeds from our issuance on October 1, 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes on October 22, 2004, which generated net proceeds of approximately \$1.4 billion and the sale of 16.1 million shares of common stock on October 27, 2004, which generated net proceeds of approximately \$382.0 million.

As a result of the acquisition, effective October 1, 2004, we created the pipeline and storage segment which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC, which was previously included in our other nonutility segment.

The TXU Gas acquisition essentially doubled the size of the Company as measured by assets, revenues and customers. The following table presents selected financial information for the Mid-Tex Division and Atmos Pipeline — Texas Division operations for the three and nine-month periods ended June 30, 2005:

	Three Months Ended June 30, 2005		Nine Months Ended June 30, 2005	
	Mid-Tex Division	Atmos Pipeline — Texas Division	Mid-Tex Division	Atmos Pipeline — Texas Division
	(In thousands, unless otherwise noted)			
Operating revenues	\$209,255	\$33,261	\$1,133,913	\$118,675
Gross profit	79,428	35,222	324,542	111,447
Operation and maintenance	30,780	12,012	110,219	39,461
Depreciation and amortization	15,245	3,896	48,327	11,300
Taxes, other than income	30,971	1,905	83,994	6,000
Operating income	2,432	17,409	82,002	54,686
Miscellaneous income	1,284	18	2,280	27
Interest charges	12,092	5,900	35,533	17,646
Income tax expense (benefit)	(2,947)	4,038	17,102	12,981
Net income (loss)	\$ (5,429)	\$ 7,489	\$ 31,647	\$ 24,086
Utility sales volumes — MMcf	17,731	NA	114,365	NA
Utility transportation volumes — MMcf	10,868	NA	36,336	NA
Total utility throughput — MMcf	<u>28,599</u>	<u>NA</u>	<u>150,701</u>	<u>NA</u>
Pipeline transportation volumes — MMcf	<u>NA</u>	<u>97,567</u>	<u>NA</u>	<u>254,528</u>
Heating Degree Days — Percent of Normal	87%	NA	80%	NA

The impact of the TXU Gas acquisition, combined with continued strong performance in our natural gas marketing segment contributed to the following financial results during the nine months ended June 30, 2005:

- Our utility segment net income increased by \$32.9 million. The increase reflects the impact of the acquisition of the Mid-Tex operations (\$31.6 million) and the effect of rate increases in our West Texas and Mississippi jurisdictions that were not in effect during the first six months of fiscal 2004, partially offset by weather (adjusted for WNA) in our historical operations that was five percent warmer than normal and one percent warmer than the prior year.
- Our natural gas marketing segment net income increased \$4.5 million during the nine months ended June 30, 2005 compared with the nine months ended June 30, 2004. The increase in natural gas marketing net income primarily reflects favorable results from the management of our storage portfolio partially offset by an unfavorable movement in the forward indices used to value our storage financial instruments.
- Our pipeline and storage segment contributed \$28.6 million in net income for the nine months ended June 30, 2005 compared with \$2.6 million for the nine months ended June 30, 2004, primarily reflecting the acquisition of the Atmos Pipeline — Texas Division (\$24.1 million).
- Our total debt to capitalization ratio at June 30, 2005 was 57.5 percent compared with 43.3 percent at September 30, 2004 reflecting the impact of the financing for the TXU Gas acquisition, partially offset by the repayment of \$72.5 million in principal of substantially all of our First Mortgage bonds in June 2005.

- Operating cash flow provided \$387.4 million compared with \$359.3 million, reflecting increased net income, more effective net working capital management partially offset by lower than expected utility sales volumes due to the effect of warmer weather.
- Capital expenditures increased to \$226.9 million from \$129.5 million primarily reflecting spending for the Mid-Tex Division (\$77.8 million) and the Atmos Pipeline — Texas Division (\$16.3 million).

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, 2004 and includes 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 on a quarterly basis. There have been no significant changes to these critical accounting policies during the nine months ended June 30, 2005.

Results of Operations

The following table presents our financial highlights for the three and nine-month periods ended June 30, 2005 and 2004:

	Three Months Ended June 30		Nine Months Ended June 30	
	2005	2004	2005	2004
	(In thousands, unless otherwise noted)			
Operating revenues	\$909,952	\$546,058	\$3,968,699	\$2,427,159
Gross profit	224,349	107,492	927,384	472,671
Operating expenses	184,881	86,032	587,061	282,256
Operating income	39,468	21,460	340,323	190,415
Miscellaneous income	1,524	2,187	2,867	7,850
Interest charges	33,689	16,011	99,304	49,506
Income before income taxes	7,303	7,636	243,886	148,759
Income tax expense	2,817	2,871	91,299	56,148
Net income	\$ 4,486	\$ 4,765	\$ 152,587	\$ 92,611
Utility sales volumes — MMcf	43,925	25,146	263,077	153,011
Utility transportation volumes — MMcf	<u>28,753</u>	<u>17,428</u>	<u>88,635</u>	<u>55,573</u>
Total utility throughput — MMcf	<u>72,678</u>	<u>42,574</u>	<u>351,712</u>	<u>208,584</u>
Natural gas marketing sales volumes — MMcf	<u>52,739</u>	<u>47,640</u>	<u>179,679</u>	<u>173,729</u>
Pipeline transportation volumes — MMcf	<u>97,567</u>	<u>—</u>	<u>254,528</u>	<u>—</u>
Heating degree days ⁽¹⁾				
Actual (weighted average)	167	237	2,580	3,249
Percent of normal	97%	94%	89%	96%
Consolidated utility average transportation revenue per Mcf	\$ 0.48	\$ 0.39	\$ 0.53	\$ 0.42
Consolidated utility average cost of gas per Mcf sold	\$ 7.43	\$ 6.49	\$ 7.20	\$ 6.56

⁽¹⁾ Adjusted for service areas that have weather normalized operations.

The following tables show our operating income (loss) by segment for the three-month and nine-month periods ended June 30, 2005 and 2004. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30			
	2005		2004	
	Operating Income (Loss)	Heating Degree Days Percent of Normal ⁽⁴⁾	Operating Income (Loss)	Heating Degree Days Percent of Normal ⁽⁴⁾
	(In thousands, except degree day information)			
Colorado-Kansas	\$ 2,451	105%	\$ 845	96%
Kentucky	1,260	105%	3,089	85%
Louisiana	4,358	63%	5,625	115%
Mid-States	1,600	99%	1,367	83%
Mid-Tex ⁽¹⁾	2,432	87%	—	—
Mississippi ⁽²⁾	(2,455)	100%	(1,559)	116%
West Texas	4,992	100%	4,291	96%
Other	403	—	(466)	—
Utility segment	15,041	97%	13,192	94%
Natural gas marketing segment	4,747	—	6,847	—
Pipeline and storage segment ⁽³⁾	19,356	—	1,075	—
Other nonutility segment and other	324	—	346	—
Consolidated operating income	<u>\$39,468</u>	97%	<u>\$21,460</u>	94%

	Nine Months Ended June 30			
	2005		2004	
	Operating Income	Heating Degree Days Percent of Normal ⁽⁴⁾	Operating Income	Heating Degree Days Percent of Normal ⁽⁴⁾
	(In thousands, except degree day information)			
Colorado-Kansas	\$ 26,934	99%	\$ 20,202	99%
Kentucky	17,863	98%	20,895	98%
Louisiana	26,941	78%	35,326	93%
Mid-States	37,443	94%	38,751	95%
Mid-Tex ⁽¹⁾	82,002	80%	—	—
Mississippi ⁽²⁾	24,661	96%	23,805	101%
West Texas	26,080	100%	18,458	91%
Other	1,402	—	604	—
Utility segment	243,326	89%	158,041	96%
Natural gas marketing segment	34,141	—	26,729	—
Pipeline and storage segment ⁽³⁾	61,959	—	5,125	—
Other nonutility segment and other	897	—	520	—
Consolidated operating income	<u>\$340,323</u>	89%	<u>\$190,415</u>	96%

Notes to preceding tables:

- (1) Operating income for the Mid-Tex Division reflects operating income since October 1, 2004.
- (2) The name of this division was changed from the Mississippi Valley Gas Company Division in April 2005.
- (3) Operating income for the pipeline and storage segment reflects operating income for the Atmos Pipeline — Texas Division since October 1, 2004.
- (4) Adjusted for service areas that have weather normalized operations.

Three Months Ended June 30, 2005 compared with Three Months Ended June 30, 2004

Utility segment

Our utility segment has historically contributed 70 to 85 percent of our consolidated net income. The primary factors that impact the results of our utility operations are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas sales to residential, commercial and public-authority customers are affected by winter heating season requirements. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 68 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations. Utility sales to industrial customers are much less weather sensitive. Utility sales to agricultural customers, which typically use natural gas to power irrigation pumps during the period from March through September, are primarily affected by rainfall amounts and the price of natural gas.

Changes in the cost of gas impact revenue but do not directly affect our gross profit from utility operations because the fluctuations in gas prices are passed through to our customers. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense.

The effects of weather that is above or below normal are partially offset through weather normalization adjustments, or WNA, in certain of our service areas. WNA allows us to increase the base rate portion of customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal. As of June 30, 2005, we had, or received regulatory approvals for, WNA in the following service areas for the following periods, which covered approximately 1.1 million meters:

Georgia	October – May
Kansas	October – May
Kentucky	November – April
Mississippi	November – May
Tennessee	November – April
Amarillo, Texas	October – May
West Texas	October – May
Lubbock, Texas	October – May
Virginia ⁽¹⁾	January – December

⁽¹⁾ Effective beginning in July 2005.

Our Mid-Tex Division does not have WNA. However, its operations benefit from a rate structure that combines a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provides for the recovery of a significant portion of our fixed costs for such operations under average weather conditions. However, this rate structure is not as beneficial during periods where weather is significantly warmer than normal.

Operating Income

Utility gross profit increased to \$175.2 million for the three months ended June 30, 2005 from \$93.2 million for the three months ended June 30, 2004. Total throughput for our utility business was 72.7 billion cubic feet (Bcf) during the current year compared to 42.6 Bcf in the prior year period.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of the Mid-Tex Division resulting in an increase in utility gross profit margin and total throughput of \$79.4 million and 28.6 Bcf. Gross profit margin in our historical operations increased by \$2.6 million primarily due to weather that was 6 percent colder than the prior year quarter partially offset by lower irrigation margins in our West Texas and Colorado-Kansas Divisions.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$160.2 million for the three months ended June 30, 2005 from \$80.0 million for the three months ended June 30, 2004 as a result of the addition of the Mid-Tex Division. Excluding the impact of the Mid-Tex Division, operating expenses for our historical utility operations increased 4 percent compared with the prior year period. Included in taxes other than income taxes are franchise and state gross receipts taxes which are paid by our customers as a component of their monthly bills. Although these amounts are offset in revenues through customer billings, timing differences between when the expense is incurred and is recovered may impact our net income on a temporary basis. However, there is no permanent effect on net income.

As a result of the aforementioned factors, our utility segment operating income for the three months ended June 30, 2005 increased to \$15.0 million from \$13.2 million for the three months ended June 30, 2004.

Miscellaneous Income

Miscellaneous income increased to \$3.1 million for the three months ended June 30, 2005 from \$1.7 million for the three months ended June 30, 2004. The increase was attributable to an increase in interest income earned on higher cash balances during the third quarter compared with the prior year quarter partially offset by a \$0.8 million gain on the sale of a building during the three months ended June 30, 2004.

Interest Charges

Interest charges allocated to the utility segment for the three months ended June 30, 2005 increased to \$28.5 million from \$16.1 million for the three months ended June 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Mid-Tex Division in October 2004. On June 30, 2005, we repaid \$72.5 million in principal on five of our First Mortgage Bonds prior to their scheduled maturities. The early extinguishment of these bonds will result in savings of \$1.3 million in interest expense in fiscal 2005.

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 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 the most advantageous price 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.

Operating Income

Gross profit margin for our natural gas marketing segment consists primarily of marketing activities, which represent the utilization of proprietary and customer-owned transportation and storage assets to provide the various services our customers request, and storage activities, which are derived from the optimization of our managed proprietary and third party storage and transportation assets.

Our natural gas marketing segment's gross profit margin was comprised of the following for the three months ended June 30, 2005 and 2004:

	Three Months Ended June 30	
	<u>2005</u>	<u>2004</u>
	(In thousands, except storage balances)	
Storage Activities		
Realized margin	\$(1,777)	\$ 2,621
Unrealized margin	<u>961</u>	<u>2,968</u>
Total Storage Activities	(816)	5,589
Marketing Activities		
Realized margin	12,347	9,147
Unrealized margin	<u>(1,136)</u>	<u>(3,105)</u>
Total Marketing Activities	<u>11,211</u>	<u>6,042</u>
Gross profit	<u>\$10,395</u>	<u>\$11,631</u>
Ending storage balance (Bcf)	<u>14.7</u>	<u>4.9</u>

Our natural gas marketing segment's gross profit margin was \$10.4 million for the three months ended June 30, 2005 compared to gross profit of \$11.6 million for the three months ended June 30, 2004. Gross profit margin from our natural gas marketing segment for the three months ended June 30, 2005 included an unrealized loss of \$0.2 million compared with an unrealized loss of \$0.1 million in the prior-year period. Natural gas marketing sales volumes were 62.8 Bcf during the three months ended June 30, 2005 compared with 56.2 Bcf for the prior year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 52.7 Bcf during the current year period compared with 47.6 Bcf in the prior year period. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies into new market areas.

The contribution to gross profit from our storage activities was a loss of \$0.8 million for the three months ended June 30, 2005 compared to a gain of \$5.6 million for the three months ended June 30, 2004. The \$6.4 million decrease primarily was attributable to a \$4.4 million decrease in the realized storage contribution for the three months ended June 30, 2005 compared to the prior year period associated with increased storage costs related to 9.0 Bcf in new storage capacity contracted during the third quarter and less favorable arbitrage spreads from increased market volatility. The total annual demand charge for the new storage capacity will be \$7.6 million. We may further increase the amount of our storage capacity during the remainder of fiscal 2005; therefore, the impact of price volatility on our unrealized storage contribution could become more significant in future periods.

A \$2.0 million decrease in the unrealized storage contribution resulting from an unfavorable movement during the three months ended June 30, 2005 in the forward indices used to value the storage financial instruments combined with greater physical natural gas storage quantities at June 30, 2005 compared to the prior year period also contributed to the decrease.

Our marketing activities contributed \$11.2 million to our gross profit for the three months ended June 30, 2005 compared to \$6.0 million for the three months ended June 30, 2004. The increase in the marketing contribution primarily was attributable to focusing our marketing efforts on higher margin customers and successfully entering into new market areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$5.6 million for the three months ended June 30, 2005 from \$4.8 million for the three months ended June 30, 2004. The increase in operating expense was attributable primarily to an increase in labor costs due to increased headcount and an increase in regulatory compliance costs.

The decrease in gross profit margin, combined with higher operating expenses resulted in a decrease in our natural gas marketing segment operating income to \$4.7 million for the three months ended June 30, 2005 compared with operating income of \$6.8 million for the three months ended June 30, 2004.

Pipeline and Storage Segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC, which were previously included in our other nonutility segment. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, blending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

Atmos Pipeline and Storage, LLC, owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations provide all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of this division.

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.

Operating Income

Pipeline and storage gross profit increased to \$38.3 million for the three months ended June 30, 2005 from \$2.2 million for the three months ended June 30, 2004. Total pipeline transportation volumes were 128.5 Bcf during the three months ended June 30, 2005 compared with 2.1 Bcf for the prior year period.

Excluding intersegment transportation volumes, total pipeline transportation volumes were 97.6 Bcf during the current year period.

The increase in pipeline and storage gross profit margin primarily reflects the impact of the acquisition of the Atmos Pipeline — Texas Division resulting in an increase in pipeline and storage gross profit margin and total transportation volumes of \$35.2 million and 97.6 Bcf. Also contributing to Atmos Pipeline — Texas Division's results were higher transportation and related services margin due to significant basis differentials at its three major Texas hubs. The \$0.8 million increase in the gross profit generated by Atmos Pipeline and Storage, LLC primarily reflects an increase in asset management fees.

Operating expenses increased to \$18.9 million for the three months ended June 30, 2005 from \$1.1 million for the three months ended June 30, 2004 due to the addition of \$17.8 million in operating expenses associated with the Atmos Pipeline — Texas Division. As the Atmos Pipeline — Texas Division is a regulated entity, franchise and state gross receipts taxes are paid by our customers; thus, these amounts are offset in revenues through customer billings and have no effect on net income. Included in operating expense was \$2.1 million associated with taxes other than income taxes, of which \$1.9 million was associated with our Atmos Pipeline — Texas Division.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the three months ended June 30, 2005 increased to \$19.4 million from \$1.1 million for the three months ended June 30, 2004.

Interest Charges

Interest charges allocated to this segment for the three months ended June 30, 2005 increased to \$6.2 million from \$0.3 million for the three months ended June 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Atmos Pipeline — Texas Division in October 2004.

Other Nonutility Segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. Through AES, we provide natural gas management services to our utility operations. These services, which began April 1, 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we construct gas-fired electric peaking power-generating plants and associated facilities and may enter into agreements to either lease or sell these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002. Operating income during the three months ended June 30, 2005 was flat compared with the prior year quarter.

Miscellaneous income for the three months ended June 30, 2005 was \$0.6 million compared with \$1.5 million for the three months ended June 30, 2004. The \$0.9 million decrease was attributable primarily to the recognition of a \$1.0 million pretax gain on the sale of all remaining limited partnership interests in Heritage Propane Partners, L.P. during the third quarter of fiscal 2004.

Nine Months Ended June 30, 2005 compared with Nine Months Ended June 30, 2004

Utility Segment

Operating Income

Utility gross profit increased to \$755.6 million for the nine months ended June 30, 2005 from \$421.0 million for the nine months ended June 30, 2004. Total throughput for our utility business was 351.7 billion cubic feet (Bcf) during the current year compared to 208.6 Bcf in the prior year.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of the Mid-Tex Division resulting in an increase in utility gross profit margin and total throughput of \$324.5 million and 150.7 Bcf. The \$10.1 million increase in the gross profit generated from our historical operations primarily reflects rate increases in our Mississippi and West Texas jurisdictions that were absent in the prior year period coupled with the recognition of a \$1.9 million refund to our customers in our Colorado service area in the prior year period. These increases were partially offset by lower gross profit margins, primarily in our Louisiana service area, due to weather (as adjusted for jurisdictions with weather-normalized operations) that was five percent warmer than normal and one percent warmer than the prior year period. Additionally, gross profit margin was adversely impacted by the lack of cold weather in patterns sufficient to encourage customers to increase their heat load consumption.

Operating expenses increased to \$512.3 million for the nine months ended June 30, 2005 from \$263.0 million for the nine months ended June 30, 2004 as a result of the addition of the Mid-Tex Division. Excluding the impact of the Mid-Tex Division, operating expenses for our historical utility operations increased \$6.7 million primarily due to a \$5.6 million increase in taxes, other than income and a \$3.6 million increase in depreciation and amortization, partially offset by lower operating and maintenance expenses due to cost control efforts.

As a result of the aforementioned factors, our utility segment operating income for the nine months ended June 30, 2005 increased to \$243.3 million from \$158.0 million for the nine months ended June 30, 2004.

Miscellaneous Income

Miscellaneous income increased to \$6.1 million for the nine months ended June 30, 2005 from \$4.0 million for the nine months ended June 30, 2004. The increase was attributable to an increase in interest income earned on higher cash balances compared with the prior year partially offset by a \$0.8 million gain on the sale of a building during the quarter ended June 30, 2004.

Interest Charges

Interest charges allocated to the utility segment for the nine months ended June 30, 2005 increased to \$83.8 million from \$49.3 million for the nine months ended June 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Mid-Tex Division in October 2004.

Natural Gas Marketing Segment

Operating Income

Our natural gas marketing segment's gross profit margin was comprised of the following for the nine months ended June 30, 2005 and 2004:

	Nine Months Ended June 30	
	2005	2004
	(In thousands, except storage balances)	
Storage Activities		
Realized margin	\$15,482	\$ 6,766
Unrealized margin	(7,065)	363
Total Storage Activities	8,417	7,129
Marketing Activities		
Realized margin	43,182	36,417
Unrealized margin	(3,200)	(2,555)
Total Marketing Activities	39,982	33,862
Gross profit	<u>\$48,399</u>	<u>\$40,991</u>
Ending storage balance (Bcf)	<u>14.7</u>	<u>4.9</u>

Our natural gas marketing segment's gross profit margin was \$48.4 million for the nine months ended June 30, 2005 compared to gross profit of \$41.0 million for the nine months ended June 30, 2004. Gross profit margin from our natural gas marketing segment for the nine months ended June 30, 2005 included an unrealized loss of \$10.3 million compared with an unrealized loss of \$2.2 million in the prior-year period. Natural gas marketing sales volumes were 203.8 Bcf during the nine months ended June 30, 2005 compared with 207.6 Bcf for the prior year period. Excluding intersegment sales volumes, natural gas marketing sales volumes were 179.7 Bcf during the current year period compared with 173.7 Bcf in the prior year period. The slight increase in consolidated natural gas marketing sales volumes was primarily due to focusing our marketing efforts on higher margin opportunities and successful marketing efforts into new market areas partially offset by warmer-than-normal weather across our market areas.

The contribution to gross profit from our storage activities was a gain of \$8.4 million for the nine months ended June 30, 2005 compared to a gain of \$7.1 million for the nine months ended June 30, 2004. The \$1.3 million improvement primarily was attributable to an \$8.7 million improvement in the realized storage contribution, partially offset by a \$7.4 million decrease in the unrealized storage contribution for the nine months ended June 30, 2005 compared to the prior year period. The improvement in the realized storage contribution for the nine months ended June 30, 2005 primarily was due to higher physical storage volumes and more favorable arbitrage spreads from increased market activity. The decrease in unrealized income in the current period was primarily attributable to an unfavorable movement during the nine months ended June 30, 2005 in the forward indices used to value the storage financial instruments combined with greater physical natural gas storage quantities at June 30, 2005 compared to the prior-year period.

Our marketing activities contributed \$40.0 million to our gross profit for the nine months ended June 30, 2005 compared to \$33.9 million for the nine months ended June 30, 2004. The increase in the marketing contribution primarily was attributable to improved realized margins resulting from focusing our marketing efforts on higher margin customers and successful marketing efforts into new market areas, partially offset by the recognition of previously unrealized losses related to the open fixed-price forward contracts that were designated as cash flow hedges on April 1, 2004.

Operating expenses remained unchanged at \$14.3 million for the nine months ended June 30, 2005 compared to the nine months ended June 30, 2004.

The improved gross profit margin and unchanged operating expenses resulted in an increase in our natural gas marketing segment operating income to \$34.1 million for the nine months ended June 30, 2005 compared with operating income of \$26.7 million for the nine months ended June 30, 2004.

Pipeline and Storage Segment

Operating Income

Pipeline and storage gross profit increased to \$121.9 million for the nine months ended June 30, 2005 from \$9.1 million for the nine months ended June 30, 2004. Total pipeline transportation volumes were 417.4 Bcf during the nine months ended June 30, 2005 compared with 7.4 Bcf for the prior year period. Excluding intersegment transportation volumes, total pipeline transportation volumes were 254.5 Bcf during the current year period.

The increase in pipeline and storage gross profit margin primarily reflects the impact of the acquisition of the Atmos Pipeline — Texas Division resulting in an increase in pipeline and storage gross profit margin and total transportation volumes of \$111.4 million and 254.5 Bcf. The \$1.4 million increase in the gross profit generated by Atmos Pipeline and Storage, LLC primarily reflects an increase in asset management fees coupled with an unrealized gain of \$0.6 million compared with an unrealized loss in the prior year period of \$0.1 million.

Operating expenses increased to \$59.9 million for the nine months ended June 30, 2005 from \$4.0 million for the nine months ended June 30, 2004 due to the addition of \$56.8 million in operating expenses associated with the Atmos Pipeline — Texas Division. Included in operating expense was \$6.5 million associated with taxes other than income taxes, of which \$6.0 million was associated with our Atmos Pipeline — Texas Division.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the nine months ended June 30, 2005 increased to \$62.0 million from \$5.1 million for the nine months ended June 30, 2004.

Interest Charges

Interest charges allocated to this segment for the nine months ended June 30, 2005 increased to \$18.6 million from \$0.8 million for the nine months ended June 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Atmos Pipeline — Texas Division in October 2004.

Other Nonutility Segment

Operating income during the nine months ended June 30, 2005 was flat compared with the prior year quarter and reflects the absence of a one time charge of \$0.4 million associated with the wind-down of a noncore business.

Miscellaneous income for the nine months ended June 30, 2005 was \$1.8 million, compared with income of \$7.7 million for the nine months ended June 30, 2004. The \$5.9 million decrease was attributable to the recognition of a \$5.9 million pretax gain associated with the sale by U.S. Propane L.P. (USP) of its general and limited partnership interests in Heritage Propane Partners, L.P. during the nine months ended June 30, 2004.

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 and funds raised from the public debt and equity capital markets. We believe that these sources of funds will provide the necessary working capital and liquidity for capital expenditures and other cash needs for the remainder of fiscal 2005.

Capitalization

The following presents our capitalization as of June 30, 2005 and September 30, 2004:

	June 30, 2005		September 30, 2004	
	(In thousands, except percentages)			
Short-term debt	\$	—	\$	—
Long-term debt	2,186,881	57.5%	867,219	43.3%
Shareholders' equity	<u>1,616,010</u>	<u>42.5%</u>	<u>1,133,459</u>	<u>56.7%</u>
Total capitalization, including short-term debt	<u>\$3,802,891</u>	<u>100.0%</u>	<u>\$2,000,678</u>	<u>100.0%</u>

Total debt as a percentage of total capitalization, including short-term debt, was 57.5 percent at June 30, 2005, and 43.3 percent at September 30, 2004. The increase in the debt to capitalization ratio was attributable to the issuance of \$1.39 billion in senior unsecured long-term debt, partially offset by the issuance of 16.1 million shares of our common stock in October 2004 to partially finance the TXU Gas acquisition. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. Within three to five years from the closing of the acquisition, we intend to reduce our capitalization ratio to 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, access to the equity capital markets and reduced annual maintenance and capital expenditures.

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, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of the natural gas distribution and pipeline operations of TXU Gas we acquired and other factors.

Cash flows from operating activities

Year-over-year changes in our operating cash flows are attributable primarily to changes in net income, working capital changes within our utility segment resulting from the impact of weather, 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, 2005, we generated operating cash flow of \$387.4 million compared with \$359.3 million for the nine months ended June 30, 2004. Our cash flow from operating activities was affected by the following:

- Favorable movements during the nine months ended June 30, 2005 in the market indices used to value our risk management assets and liabilities favorably impacted operating cash flow by \$9.8 million. However, unfavorable movements in the market indices used to value our natural gas marketing segment risk management assets and liabilities resulted in a net liability for that segment. Accordingly, under the terms of the associated derivative contracts, we were required to deposit \$22.7 million into a margin account, which resulted in a \$40.6 million unfavorable impact to operating cash flow compared with the prior year period.
- The timing of payments for accounts payable and other accrued liabilities favorably affected operating cash flow by \$32.0 million.
- Increases in our natural gas inventories attributable to a 10 percent higher utility average cost of gas and increased natural gas marketing natural gas inventory levels compared with the prior year period resulted in a \$74.3 million decrease in operating cash flows.

- The lag between the time period when we purchase our natural gas and the period in which we can include this cost in our gas rates resulted in a decrease in operating cash flows of \$32.7 million.
- Other working capital and other changes positively affected operating cash flow by \$133.9 million, primarily related to improved net income (\$60.0 million) and increases in the amounts added back to net income for depreciation and amortization (\$62.9 million) and deferred income taxes (\$12.0 million).

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources was used to fund acquisitions, our ongoing construction program to provide natural gas services to our customer base, enhance the integrity of our pipelines and improvements to information systems. Capital expenditures for fiscal 2005 are expected to range from \$335 million to \$345 million. Of this amount, approximately \$150 — \$160 million is expected to be incurred by the Mid-Tex Division and Atmos Pipeline — Texas Division.

For the nine months ended June 30, 2005, we incurred \$226.9 million for capital expenditures compared with \$129.5 million for the nine months ended June 30, 2004. Capital expenditures for the nine months ended June 30, 2005 include approximately \$77.8 million for the Atmos Energy Mid-Tex Division and \$16.3 million for the Atmos Pipeline — Texas Division.

Our cash used for investing activities for the nine months ended June 30, 2005 reflects the \$1.9 billion cash paid for the TXU Gas acquisition including related transaction costs and expenses. Cash flow from investing activities for the nine months ended June 30, 2004 reflect the receipt of \$26.6 million from the sale of our limited and general partnership interests in USP in January 2004 and \$1.3 million from the sale of a building.

Cash flows from financing activities

For the nine months ended June 30, 2005, our financing activities provided \$1.6 billion in cash compared with a use of cash of \$144.0 million for the prior year period. Our significant financing activities for the nine months ended June 30, 2005 and 2004 are summarized as follows:

- In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option of 2.1 million shares, under a new shelf registration statement declared effective in September 2004, generating net proceeds of \$382.0 million. Additionally, we issued senior unsecured debt under the shelf registration statement consisting of \$400 million of 4.00% senior notes due 2009, \$500 million of 4.95% senior notes due 2014, \$200 million of 5.95% senior notes due 2034 and \$300 million of floating rate senior notes due 2007. The floating rate notes bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. The net proceeds received from the sale of these senior notes were \$1.39 billion. The net proceeds from these issuances, combined with the net proceeds from our July 2004 offering were used to pay off the approximately \$1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition.
- During the nine months ended June 30, 2005 we borrowed and repaid all amounts borrowed under our commercial paper program. During the nine months ended June 30, 2004, we repaid \$118.6 million under our commercial paper program. Strong operating cash flow in each year to date period provided sufficient funds to enable us to repay all outstanding amounts under our commercial paper program as of June 30, 2005 and June 30, 2004.
- We repaid \$102.8 million of long-term debt during the nine months ended June 30, 2005 compared with \$9.1 million during the nine months ended June 30, 2004. The increased payments during the current quarter reflected the repayment of \$72.5 million on our First Mortgage Bonds. In connection with this repayment we paid a \$25.0 million make-whole premium in accordance with the terms of the agreements and paid accrued interest of approximately \$1.0 million. In accordance with regulatory requirements, the premium has been deferred and will be recognized over the remaining original lives

of the First Mortgage Bonds that were repaid. The early extinguishment of these bonds will result in interest savings of \$1.3 million in fiscal 2005 and \$5.1 million in fiscal 2006.

- During the nine months ended June 30, 2005 we paid \$74.0 million in cash dividends compared with dividend payments of \$47.6 million for the nine months ended June 30, 2004. The increase in dividends paid over the prior year period reflects the 27.7 million increase in the number of common shares outstanding and an increase in the dividend rate from \$0.915 per share during the nine months ended June 30, 2004 to \$0.930 per share during the nine months ended June 30, 2005.
- During the nine months ended June 30, 2005 we issued 1.3 million shares of common stock, in addition to the 16.1 million common shares issued in our October 2004 public offering, which generated net proceeds of \$32.2 million. The following table summarizes the issuances for the nine months ended June 30, 2005 and 2004:

	Nine Months Ended June 30	
	2005	2004
Shares issued:		
Retirement Savings Plan	338,520	241,257
Direct Stock Purchase Plan	353,512	426,960
Outside Directors Stock-for-Fee Plan	1,769	2,358
Long-Term Incentive Plan	655,684	426,943
Long-Term Stock Plan for Mid-States Division	—	6,000
Public Offering	<u>16,100,000</u>	<u>—</u>
Total shares issued	<u>17,449,485</u>	<u>1,103,518</u>

Shelf Registration

In August 2004, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$2.2 billion in new common stock and/or debt, which became effective on September 15, 2004. In October 2004, we sold 16.1 million common shares and issued \$1.4 billion in unsecured senior notes to partially finance the TXU Gas acquisition. After these issuances, we have approximately \$401.5 million of availability remaining under the shelf registration statement.

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 bank. 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. Our cash needs for working capital and capital expenditures have increased substantially as a result of the acquisition of the natural gas distribution and pipeline operations of TXU Gas. On October 22, 2004, we replaced our \$350.0 million credit facility with a new \$600.0 million committed credit facility that serves as a backup liquidity facility for our commercial paper program. We believe this facility, combined with our operating cash flow will be sufficient to fund these increased working capital needs. On March 30, 2005, AEM amended and extended its uncommitted demand working capital credit facility to March 31, 2006. At June 30, 2005 we had no borrowings under these facilities. These facilities are described in further detail in Note 6 to the condensed consolidated financial statements.

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, Inc. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
Long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, S&P and Moody's maintain a stable outlook and Fitch maintains a negative outlook. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. All of our current ratings for long-term debt are categorized as investment grade. 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 are required by the financial covenants in our \$600.0 million credit facility 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, 2005, our total-debt-to-total-capitalization ratio, as defined in such facility, was 60 percent.

AEM is required by the financial covenants in its uncommitted demand working capital facility to maintain 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 \$50 million. Additionally, AEM must maintain a minimum tangible net worth ranging from \$21 million to \$51 million, and its maximum cumulative loss from March 30, 2005 cannot exceed \$4 million to \$10 million, depending on the total amount of borrowing elected from time to time by AEM. At June 30, 2005, AEM's ratio of total liabilities to tangible net worth, as defined in such facility, was 1.14 to 1.

Our 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 our accumulated net income for periods after December 31, 1985, plus \$9.0 million. At June 30, 2005, approximately \$199.6 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 June 30, 2005. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our \$600.0 million revolving credit agreement, 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.

Contractual Obligations and Commercial Commitments

As a result of the issuance of our unsecured senior notes in October 2004 our contractual obligations associated with our long-term debt and interest expense increased since September 30, 2004.

The following table reflects the significant changes in our contractual obligations as of June 30, 2005.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years (In thousands)	3-5 Years	After 5 Years
Contractual Obligations					
Long-term debt ⁽¹⁾	\$2,190,766	\$ 3,242	\$307,323	\$403,689	\$1,476,512
Interest charges	1,172,168	112,519	219,562	195,529	644,558
Gas purchase commitments ⁽²⁾ . . .	501,803	84,604	329,097	42,578	45,524

⁽¹⁾ See Note 6 to the consolidated financial statements.

⁽²⁾ Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of June 30, 2005.

Additionally, in January 2005, we signed a letter of intent with a third party to jointly construct, own and operate a 45-mile large diameter natural gas pipeline in the northern portion of the Dallas/Fort Worth Metroplex. Under terms of the letter of intent, the third party will provide the initial capital to build the pipeline and we will contribute up to \$42.5 million within two years of signing a definitive agreement.

In May 2005, we entered into a five year agreement with a third party to transport up to 100,000 MMBtu per day of natural gas through our Texas intrastate pipeline system beginning in April 2006. To handle the increased volumes for this project and other planned projects, we will install near Howard, Texas, compression equipment and other pipeline infrastructure, costing approximately \$20 million.

During the three months ended June 30, 2005, we contracted for an additional 9.0 Bcf of storage capacity for a total annual demand charge of \$7.6 million.

There were no other significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2005.

Risk Management Activities

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to protect us and our customers against 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 hedges, we could experience significant 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.

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 utility and natural gas marketing commodity derivative contracts for the three and nine months ended June 30, 2005 and 2004:

	Three Months Ended June 30, 2005		Three Months Ended June 30, 2004	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period . . .	\$24,367	\$(5,896)	\$ 294	\$1,187
Contracts realized/settled	163	(7,843)	849	(836)
Other changes in value	926	5,684	(8,581)	144
Fair value of contracts at end of period.	<u>\$25,456</u>	<u>\$(8,055)</u>	<u>\$(7,438)</u>	<u>\$ 495</u>

	Nine Months Ended June 30, 2005		Nine Months Ended June 30, 2004	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period . .	\$ (8,612)	\$ 13,018	\$(7,739)	\$10,144
Contracts realized/settled	(45,234)	(24,377)	(3,296)	(6,030)
Other changes in value	79,302	3,304	3,597	(3,619)
Fair value of contracts at end of period.	<u>\$ 25,456</u>	<u>\$(8,055)</u>	<u>\$(7,438)</u>	<u>\$ 495</u>

The fair value of our utility and natural gas marketing derivative contracts at June 30, 2005, is segregated below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at June 30, 2005				Total Fair Value
	Maturity in Years				
	Less than 1	1-3	4-5	Greater than 5	
	(In thousands)				
Prices actively quoted	\$19,539	\$(2,383)	\$—	\$—	\$17,156
Prices provided by other external sources	740	79	—	—	819
Prices based on models and other valuation methods	(34)	(540)	—	—	(574)
Total Fair Value	<u>\$20,245</u>	<u>\$(2,844)</u>	<u>\$—</u>	<u>\$—</u>	<u>\$17,401</u>

Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at the most advantageous price to lock in a gross profit margin. AEM is able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market monthly using the Inside FERC (iFERC) price at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, 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 changes in the difference between the indices used to mark to market our physical inventory (iFERC) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of

storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. 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. AEM monitors the impacts of these profit optimization efforts by estimating the forecasted gross profit margin that it captured through the purchase and sale of physical natural gas and the associated financial derivatives. The forecasted gross profit margin, less the effect of unrealized gains or losses recognized in the financial statements, provides a measure of the net increase or decrease in the gross profit margin that could occur in future periods if AEM's optimization efforts are fully successful.

As of June 30, 2005, based upon AEM's derivatives position and inventory withdrawal schedule, the forecasted gross profit margin was approximately \$16.4 million. Approximately \$7.8 million of net unrealized losses were recorded in the financial statements as of June 30, 2005. Therefore, the projected increase in future gross profit margin is approximately \$24.2 million.

The forecasted gross profit margin calculation is based upon planned injection and withdrawal schedules, and the realization of the forecasted gross profit margin 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 assure that the forecasted gross profit margin or the projected increase in future gross profit margin calculated as of June 30, 2005 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, permanent impacts on earnings may result.

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2005 and 2004 our total net periodic pension and other benefits cost was \$27.3 million and \$19.9 million. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The increase in total net periodic pension and other benefits cost during the current year period compared with the prior year period primarily reflects an increase in our service cost associated with an increase in the number of employees due to the TXU Gas acquisition, which increased our service cost. Additionally, we increased our discount rate and reduced our assumed rate of return on our pension plan assets for fiscal 2005, which increased our service and interest cost and reduced our expected return on plan assets, which partially offsets our net periodic pension and other benefits cost. 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. In the period leading up to our June 30, 2005 measurement date, these interest rates were declining, which has the effect of increasing the present value of our plan liabilities and our expenses. Accordingly, we expect our fiscal 2006 net periodic pension cost to increase significantly.

As a result of the expected increase in the present value of our plan liabilities resulting from the decline in interest rates, we voluntarily contributed in June 2005 \$3.0 million to our Pension Account Plan to maintain the level of funding we desire relative to our accumulated benefit obligation. We were not required to make a minimum funding contribution during fiscal 2005 nor do we anticipate making any additional voluntary contributions during the remainder of fiscal 2005. During the nine months ended June 30, 2005, we contributed \$7.0 million to our other post-retirement plans and we expect to contribute a total of \$11.7 million to these plans during fiscal 2005.

Although we did not assume the existing employee benefit liabilities or plans of TXU Gas, we agreed to give certain transitioned employees credit for years of TXU Gas service under our pension plan. For purposes of our post-retirement medical plan, we received a credit of \$18.9 million against the purchase price to permit us to provide partial past service credits for retiree medical benefits under our retiree medical plan. The \$18.9 million credit approximated the actuarially determined present value of the accumulated benefits related to the past service of the transitioned employees on the acquisition date.

Operating Statistics and Other Information

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for the three and nine-month periods ended June 30, 2005 and 2004.

Utility Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2005 ⁽¹⁾	2004	2005 ⁽¹⁾	2004
METERS IN SERVICE, end of period				
Residential	2,866,950	1,506,643	2,866,950	1,506,643
Commercial	275,878	152,025	275,878	152,025
Industrial	3,090	2,460	3,090	2,460
Agricultural	9,822	8,706	9,822	8,706
Public authority and other	8,172	10,174	8,172	10,174
Total meters	<u>3,163,912</u>	<u>1,680,008</u>	<u>3,163,912</u>	<u>1,680,008</u>
HEATING DEGREE DAYS⁽²⁾				
Actual (weighted average)	167	237	2,580	3,249
Percent of normal	97%	94%	89%	96%
UTILITY SALES VOLUMES — MMcf⁽³⁾				
Gas sales volumes				
Residential	20,528	10,842	149,774	85,223
Commercial	15,148	6,384	80,059	38,852
Industrial	5,995	4,954	23,886	17,746
Agricultural	787	1,616	913	2,421
Public authority and other	1,467	1,350	8,445	8,769
Total gas sales volumes	43,925	25,146	263,077	153,011
Utility transportation volumes	30,420	20,957	94,006	67,749
Total utility throughput	<u>74,345</u>	<u>46,103</u>	<u>357,083</u>	<u>220,760</u>
UTILITY OPERATING REVENUES (000's)⁽³⁾				
Gas sales revenues				
Residential	\$ 271,153	\$ 128,886	\$1,575,186	\$ 830,154
Commercial	141,465	60,849	731,762	348,820
Industrial	46,932	32,483	182,854	122,835
Agricultural	5,830	11,299	7,092	16,430
Public authority and other	13,160	11,607	75,332	68,553
Total utility gas sales revenues	478,540	245,124	2,572,226	1,386,792
Transportation revenues	14,095	6,987	47,839	24,058
Other gas revenues	9,100	4,141	30,728	14,172
Total utility operating revenues	<u>\$ 501,735</u>	<u>\$ 256,252</u>	<u>\$2,650,793</u>	<u>\$1,425,022</u>
Utility average transportation revenue per Mcf	\$ 0.46	\$ 0.33	\$ 0.51	\$ 0.36
Utility average cost of gas per Mcf sold	\$ 7.43	\$ 6.49	\$ 7.20	\$ 6.56

See footnotes following these tables.

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

	Three Months Ended June 30		Nine Months Ended June 30	
	2005	2004	2005	2004
CUSTOMERS, end of period				
Industrial	659	630	659	630
Municipal	79	79	79	79
Other	431	228	431	228
Total	<u>1,169</u>	<u>937</u>	<u>1,169</u>	<u>937</u>
NATURAL GAS MARKETING SALES				
VOLUMES — MMcf⁽³⁾	62,798	56,226	203,770	207,582
PIPELINE TRANSPORTATION VOLUMES —				
MMcf⁽³⁾	128,453	2,125	417,370	7,356
OPERATING REVENUES (000's)⁽³⁾				
Natural gas marketing	\$466,835	\$364,339	\$1,473,527	\$1,255,386
Pipeline and storage	36,524	5,357	130,798	18,243
Other nonutility	1,421	853	4,058	2,249
Total operating revenues	<u>\$504,780</u>	<u>\$370,549</u>	<u>\$1,608,383</u>	<u>\$1,275,878</u>

Notes to preceding tables:

- (1) The operational and statistical information includes the operations of the Mid-Tex Division and Atmos Pipeline — Texas Division since the October 1, 2004 acquisition date.
- (2) 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. Degree day information for the three and nine month periods ended June 30, 2005 and 2004 is adjusted for the Kentucky Division, the Mississippi Division and certain service areas included within the Colorado-Kansas Division, the Mid-States Division and the West Texas Division, which have weather normalized operations.
- (3) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

Recent Ratemaking Activity

The following discusses our ratemaking activities during fiscal 2005. The amounts described below represent the gross revenues that were requested or received in the 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.

Mississippi. The Mississippi Public Service Commission (MPSC) typically requires that we file for rate adjustments every six months. Rate filings have previously been made in May and November of each year and the rate adjustments typically become effective in the following July and January. During the second quarter of fiscal 2005, we agreed with the MPSC to suspend our May 2005 semi-annual filing to allow sufficient time for us and the MPSC to undertake a comprehensive review in an effort to improve our rate design and the ratemaking process.

In September 2004, the MPSC authorized additional annualized revenue of \$4.7 million on our May 2004 filing, which became effective on June 1, 2004. However, the MPSC also disallowed certain deferred costs totaling \$2.8 million. We withdrew our appeal of the MPSC's decision regarding this disallowance.

We filed our second semiannual filing for 2004 on November 5, 2004, requesting rate adjustments of \$6.0 million in annualized revenue. The MPSC allowed us to include \$3.0 million in annualized revenue in our rates effective January 1, 2005. In February 2005, we entered into a stipulation agreement with the Mississippi Public Utilities Staff that provides for an additional \$1.3 million in annualized revenue that is retroactive to January 2005, which was approved by the MPSC during the second quarter of fiscal 2005.

Mid-Tex. In December 2004, we made a filing under the Gas Reliability Infrastructure Program (GRIP) to include approximately \$32.0 million of distribution and pipeline capital expenditures made by TXU Gas during calendar year 2003, which should result in additional revenues of approximately \$6.8 million. In March 2005, the Railroad Commission of Texas (the Commission) approved the environs (outside of the city limits) portion of the filing. The Mid-Tex Division has worked with its cities to obtain approval of the filing and has a commitment from its cities to take final action by the end of August 2005. We expect these capital costs will be recovered through a monthly customer charge beginning in the first quarter of fiscal 2006. The allowed rate of return is 8.258 percent.

In September 2004, the Mid-Tex Division filed its 36-Month Gas Contract Review with the Railroad Commission of Texas (the Commission). This proceeding involves a prudence review of gas purchases totaling \$2.2 billion made by the Mid-Tex Division from November 1, 2000 through October 31, 2003. A hearing on this matter was held before the Commission in late June. Briefs from all parties are to be provided to the Commission by August 23, 2005.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last systemwide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its most recent rate case completed in May 2004. Additionally, the Mid-Tex Division is seeking the right to surcharge for gas cost underrecoveries. The case has been assigned to a judge, but the briefing schedule has been postponed indefinitely to allow the parties to pursue settlement discussions.

During the first quarter of fiscal 2005, the Mid-Tex Division pursued a filing initiated by TXU Gas seeking authorization of a surcharge to recover the rate case expenses incurred by the Mid-Tex Division, Atmos Pipeline — Texas Division, and the intervening cities in connection with their last systemwide rate case completed in May 2004. The filing also covered the estimated expenses to prosecute the aforementioned recovery docket and the severed dockets from the systemwide rate case. On January 25, 2005, the Commission issued an order authorizing the recovery of the \$10.2 million of expenses over a 3-year period with interest.

Atmos Pipeline — Texas. Concurrent with our Mid-Tex Division GRIP filing in December 2004, we also made a GRIP filing for our regulated pipeline to include approximately \$12.0 million of distribution and pipeline capital expenditures made by TXU Gas during calendar year 2003, which we anticipate will result in additional revenues of approximately \$1.8 million. The Commission approved this filing in March 2005. These capital costs are being recovered through a monthly customer charge since April 2005. The allowed rate of return is 8.258 percent.

Louisiana. During the second quarter of 2005, the Louisiana Division implemented a rate increase of \$3.3 million in its LGS service area. This increase resulted from our Rate Stabilization Clause filing in 2004 and is subject to refund pending the final resolution of that filing. As the rate increase is subject to refund, we have not recognized the effects of this increase in our results of operations for the three and nine months ended June 30, 2005.

Mid-States. During the third quarter of 2005, the Mid-States Division filed a rate case in its Georgia service area seeking a rate increase of \$4.0 million. We anticipate that the rate case will be finalized in November 2005.

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 condensed consolidated financial statements.

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

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business activities.

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to protect us and our customers against 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. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the condensed consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper, the issuance of floating rate debt in October 2004 and our other short-term borrowings.

Commodity Price Risk

Utility segment

We purchase natural gas for our utility operations. Substantially all of the cost of gas purchased for utility operations is recovered from our customers through purchased gas adjustment mechanisms. However, our utility operations have commodity price risk exposure to fluctuations in spot natural gas prices related to purchases for sales to our non-regulated energy services customers at fixed prices.

For our utility segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas cost related to fixed-price non-regulated sales. Based on projected non-regulated gas sales for the remainder of fiscal 2005, a hypothetical 10 percent increase in fixed prices, based upon the June 30, 2005 three month market strip, would increase our purchased gas cost by approximately \$3.5 million for the remainder of fiscal 2005.

Natural gas marketing and pipeline and storage segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a \$0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at June 30, 2005 of 0.2 Bcf, a \$0.50 change in the forward NYMEX price would have had less than a \$0.1 million impact on our consolidated net income.

However, changes in the difference between the indices used to mark to market our physical inventory (iFERC) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; however, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our storage position at June 30, 2005 of 15.5 Bcf, a \$0.50 change in the difference between the iFERC and NYMEX indices could impact our reported net income by approximately \$5.0 million.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short term borrowings. Had interest rates associated with our short term borrowings increased by an average of one percent, our interest expense would have increased by approximately \$0.4 million during the nine months ended June 30, 2005.

We also assess market risk for our fixed-rate, long-term obligations. We estimate market risk for our fixed-rate, long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our fixed-rate, long-term obligations would have increased by approximately \$172.4 million.

As of June 30, 2005 we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

Item 4. Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(b) and 15d-15(b). Based upon that evaluation, the Chairman, President and Chief Executive Officer, and the Senior Vice President and Chief Financial Officer have concluded that our disclosure controls and procedures continue to be effective. Such disclosure controls and procedures are designed to ensure that all information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods set forth in applicable Securities and Exchange Commission rules and forms.

In addition, our management, including the Chairman, President and Chief Executive Officer, and the Senior Vice President and Chief Financial Officer, evaluated our internal control over financial reporting pursuant to Exchange Act Rules 13a-15(d) and 15d-15(d). Based upon that evaluation, management has concluded that there has been no change in such internal control during the third quarter of fiscal 2005 that has materially affected or is 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, 2005 there were no material changes in the status of the litigation and environmental matters that were disclosed in Note 13 to our annual report on Form 10-K for the year ended September 30, 2004 except as disclosed in Note 10 to the condensed consolidated financial statements for the three months and nine months ended June 30, 2005. With the acquisition of the natural gas distribution and pipeline operations of TXU Gas Company on October 1, 2004, we assumed responsibility for certain litigation and claims that arose in the ordinary course of the business of TXU Gas Company. We believe the final outcome of such litigation and 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.

EXHIBITS INDEX
Item 6(a)

<u>Exhibit Number</u>	<u>Description</u>	<u>Page Number</u>
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.