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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, 2004

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)*

**Three Lincoln Centre, Suite 1800  
5430 LBJ Freeway, Dallas, Texas**  
*(Address of principal executive offices)*

**75-1743247**  
*(IRS Employer  
Identification No.)*

**75240**  
*(Zip code)*

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

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 August 2, 2004.

<u>Class</u>	<u>Shares Outstanding</u>
No Par Value	62,601,735

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**PART 1. FINANCIAL INFORMATION**

**Item 1. Financial Statements**

**ATMOS ENERGY CORPORATION  
CONDENSED CONSOLIDATED BALANCE SHEETS**

	<u>June 30, 2004</u>	<u>September 30, 2003</u>
	<u>(Unaudited)</u>	
	(In thousands)	
<b>ASSETS</b>		
Property, plant and equipment .....	\$2,588,059	\$2,480,139
Less accumulated depreciation and amortization .....	<u>903,313</u>	<u>855,745</u>
Net property, plant and equipment .....	1,684,746	1,624,394
Current assets		
Cash and cash equivalents .....	126,895	15,683
Cash held on deposit in margin account .....	—	17,903
Accounts receivable, net .....	243,719	216,783
Gas stored underground .....	90,141	168,765
Other current assets .....	<u>18,710</u>	<u>38,863</u>
Total current assets .....	479,465	457,997
Goodwill and intangible assets .....	275,844	273,499
Deferred charges and other assets .....	<u>240,477</u>	<u>271,023</u>
	<u>\$2,680,532</u>	<u>\$2,626,913</u>
<b>CAPITALIZATION AND LIABILITIES</b>		
Shareholders' equity		
Common stock, no par value (stated at \$.005 per share); 100,000,000 shares authorized; issued and outstanding:		
June 30, 2004 — 52,579,303 shares;		
September 30, 2003 — 51,475,785 shares .....	\$ 263	\$ 257
Additional paid-in capital .....	762,464	736,180
Retained earnings .....	167,535	122,539
Accumulated other comprehensive loss .....	<u>(3,416)</u>	<u>(1,459)</u>
Shareholders' equity .....	926,846	857,517
Long-term debt .....	<u>863,266</u>	<u>863,918</u>
Total capitalization .....	1,790,112	1,721,435
Current liabilities		
Accounts payable and accrued liabilities .....	201,123	179,852
Other current liabilities .....	210,759	133,957
Short-term debt .....	—	118,595
Current maturities of long-term debt .....	<u>5,918</u>	<u>9,345</u>
Total current liabilities .....	417,800	441,749
Deferred income taxes .....	227,899	223,350
Regulatory cost of removal obligation .....	105,059	102,371
Deferred credits and other liabilities .....	<u>139,662</u>	<u>138,008</u>
	<u>\$2,680,532</u>	<u>\$2,626,913</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

	Three Months Ended June 30	
	2004	2003
	(Unaudited)	
	(In thousands, except per share data)	
Operating revenues		
Utility segment . . . . .	\$256,252	\$ 245,998
Natural gas marketing segment . . . . .	364,339	374,832
Other nonutility segment . . . . .	6,210	3,685
Intersegment eliminations . . . . .	<u>(80,743)</u>	<u>(136,045)</u>
	546,058	488,470
Purchased gas cost		
Utility segment . . . . .	163,093	161,426
Natural gas marketing segment . . . . .	352,708	367,395
Other nonutility segment . . . . .	3,150	467
Intersegment eliminations . . . . .	<u>(80,385)</u>	<u>(135,882)</u>
	<u>438,566</u>	<u>393,406</u>
Gross profit . . . . .	107,492	95,064
Operating expenses		
Operation and maintenance . . . . .	50,467	45,141
Depreciation and amortization . . . . .	23,268	23,192
Taxes, other than income . . . . .	<u>12,297</u>	<u>12,675</u>
Total operating expenses . . . . .	<u>86,032</u>	<u>81,008</u>
Operating income . . . . .	21,460	14,056
Miscellaneous income . . . . .	2,187	686
Interest charges . . . . .	<u>16,011</u>	<u>16,042</u>
Income (loss) before income taxes . . . . .	7,636	(1,300)
Income tax expense (benefit) . . . . .	<u>2,871</u>	<u>(1,099)</u>
Net income (loss) . . . . .	<u>\$ 4,765</u>	<u>\$ (201)</u>
Per share data		
Basic income (loss) per share . . . . .	<u>\$ 0.09</u>	<u>\$ (0.00)</u>
Diluted income (loss) per share . . . . .	<u>\$ 0.09</u>	<u>\$ (0.00)</u>
Cash dividends per share . . . . .	<u>\$ .305</u>	<u>\$ .300</u>
Weighted average shares outstanding:		
Basic . . . . .	<u>52,220</u>	<u>45,997</u>
Diluted . . . . .	<u>52,617</u>	<u>45,997</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

	Nine Months Ended June 30	
	2004	2003
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Utility segment . . . . .	\$1,425,022	\$1,342,527
Natural gas marketing segment . . . . .	1,255,386	1,338,732
Other nonutility segment . . . . .	20,492	16,242
Intersegment eliminations . . . . .	<u>(273,741)</u>	<u>(334,457)</u>
	2,427,159	2,363,044
Purchased gas cost		
Utility segment . . . . .	1,003,977	934,649
Natural gas marketing segment . . . . .	1,214,395	1,325,655
Other nonutility segment . . . . .	9,158	1,475
Intersegment eliminations . . . . .	<u>(273,042)</u>	<u>(333,933)</u>
	1,954,488	1,927,846
Gross profit . . . . .	472,671	435,198
Operating expenses		
Operation and maintenance . . . . .	166,476	151,310
Depreciation and amortization . . . . .	69,879	65,273
Taxes, other than income . . . . .	45,901	44,057
Total operating expenses . . . . .	<u>282,256</u>	<u>260,640</u>
Operating income . . . . .	190,415	174,558
Miscellaneous income . . . . .	7,850	3,321
Interest charges . . . . .	49,506	47,679
Income before income taxes and cumulative effect of accounting change . . . . .	148,759	130,200
Income tax expense . . . . .	56,148	48,303
Income before cumulative effect of accounting change . . . . .	92,611	81,897
Cumulative effect of accounting change, net of income tax benefit . . . . .	<u>—</u>	<u>(7,773)</u>
Net income . . . . .	<u>\$ 92,611</u>	<u>\$ 74,124</u>
Per share data		
Basic income per share:		
Income before cumulative effect of accounting change . . . . .	\$ 1.79	\$ 1.83
Cumulative effect of accounting change, net of income tax benefit . . . . .	<u>—</u>	<u>(.17)</u>
Net income . . . . .	<u>\$ 1.79</u>	<u>\$ 1.66</u>
Diluted income per share:		
Income before cumulative effect of accounting change . . . . .	\$ 1.78	\$ 1.82
Cumulative effect of accounting change, net of income tax benefit . . . . .	<u>—</u>	<u>(.17)</u>
Net income . . . . .	<u>\$ 1.78</u>	<u>\$ 1.65</u>
Cash dividends per share . . . . .	<u>\$ .915</u>	<u>\$ .900</u>
Weighted average shares outstanding:		
Basic . . . . .	<u>51,788</u>	<u>44,679</u>
Diluted . . . . .	<u>52,166</u>	<u>44,879</u>

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

	Nine Months Ended June 30	
	2004	2003
	(Unaudited)	
	(In thousands)	
Cash Flows from Operating Activities		
Net income .....	\$ 92,611	\$ 74,124
Adjustments to reconcile net income to net cash provided by operating activities:		
Cumulative effect of accounting change, net of income tax benefit .....	—	7,773
Gain on sales of assets .....	(6,700)	—
Depreciation and amortization:		
Charged to depreciation and amortization .....	69,879	65,273
Charged to other accounts .....	1,270	1,676
Deferred income taxes .....	5,750	9,148
Other .....	(1,405)	(5,403)
Net assets/liabilities from risk management activities .....	4,469	(4,200)
Net change in operating assets and liabilities .....	193,388	(31,099)
Net cash provided by operating activities .....	359,262	117,292
Cash Flows from Investing Activities		
Capital expenditures .....	(129,508)	(113,637)
Proceeds from sales of assets .....	27,919	—
Retirements of property, plant and equipment, net .....	(505)	315
Acquisitions .....	(1,957)	(74,650)
Net cash used in investing activities .....	(104,051)	(187,972)
Cash Flows from Financing Activities		
Net decrease in short-term debt .....	(118,595)	(145,091)
Cash dividends paid .....	(47,615)	(39,893)
Repayment of long-term debt .....	(9,079)	(72,333)
Net proceeds from issuance of long-term debt .....	5,000	253,267
Issuance of common stock .....	26,290	19,336
Repayment of Mississippi Valley Gas debt .....	—	(70,938)
Proceeds from bridge loan .....	—	147,000
Repayment of bridge loan .....	—	(147,000)
Net proceeds from equity offering .....	—	96,826
Net cash provided (used) by financing activities .....	(143,999)	41,174
Net increase (decrease) in cash and cash equivalents .....	111,212	(29,506)
Cash and cash equivalents at beginning of period .....	15,683	46,827
Cash and cash equivalents at end of period .....	\$ 126,895	\$ 17,321

See accompanying notes to condensed consolidated financial statements

**ATMOS ENERGY CORPORATION**  
**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**  
**(Unaudited)**  
**June 30, 2004**

**1. Nature of Business**

Atmos Energy Corporation 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 1.7 million residential, commercial, public-authority and industrial customers through our six regulated natural gas utility divisions, which cover the following service areas:

<u>Division</u>	<u>Service Area</u>
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri <sup>(2)</sup>
Atmos Energy Kentucky Division	Kentucky
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-States Division	Georgia <sup>(2)</sup> , Illinois <sup>(2)</sup> , Iowa <sup>(2)</sup> , Missouri <sup>(2)</sup> , Tennessee, Virginia <sup>(2)</sup>
Atmos Energy Texas Division	Texas
Mississippi Valley Gas Company Division <sup>(1)</sup>	Mississippi

<sup>(1)</sup> Acquired in December 2002.

<sup>(2)</sup> Denotes locations where we have more limited service areas.

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.

As further described in Note 3, on June 17, 2004, we entered into a definitive agreement with TXU Gas Company (TXU Gas) to acquire the natural gas distribution and pipeline operations of TXU Gas. The acquisition would increase the number of customers we serve in our natural gas utility business to over 3.1 million and make us one of the largest publicly-traded companies in the United States whose primary business is the transmission and distribution of natural gas and the provision of related services. It would also make us one of the largest intrastate pipeline operators in Texas.

Our nonutility businesses are organized under Atmos Energy Holdings, Inc. (AEH), and have operations in 18 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries, Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, LLC and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C., which was renamed Atmos Energy Marketing, LLC (AEM).

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers, primarily in the southeastern and midwestern states 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 other nonutility businesses consist primarily of the operations of Atmos Pipeline and Storage, L.L.C., Atmos Power Systems, Inc. and Atmos Energy Services, LLC (AES), all of which are wholly-owned by

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

AEH. Through Atmos Pipeline and Storage, L.L.C., we own or have an interest in underground storage fields in Kentucky and Louisiana. Through Atmos Pipeline and Storage, L.L.C. we provide storage services to our customers for a fee, as well as capture pricing arbitrage through the use of derivatives. Through Atmos Power Systems, Inc., we construct electric peaking power-generating plants and associated facilities and may enter into agreements to either lease or sell these plants. Through AES, we provide natural gas management services. Prior to the third quarter of fiscal 2004, this entity conducted limited operations. However, beginning April 1, 2004, AES began providing natural gas supply management services to our utility operations in a limited number of states. We expect to expand these services to substantially all of our utility service areas before the end of fiscal 2004.

Prior to January 20, 2004, United Cities Propane Gas, Inc., a wholly owned subsidiary of AEH, owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with three other utility companies. Through our ownership in USP, we owned an approximate 5 percent indirect interest in Heritage Propane Partners, L.P. On January 20, 2004, we and our partners in USP completed the sale of our general and limited partnership interests in USP for \$130.0 million. We received cash proceeds of approximately \$24.7 million and recorded a \$4.9 million pretax book gain in the second quarter of fiscal 2004. In June 2004, we received cash proceeds of \$1.9 million attributable to the final sale of all remaining Heritage Propane Partners, L.P. limited partnership units formerly owned by USP and recognized a \$1.0 million pretax book gain. With these transactions, we no longer have an interest in the propane industry.

#### **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 (“Atmos” or “the Company”) in its Annual Report on Form 10-K for the fiscal year ended September 30, 2003. Because of seasonal and other factors, the results of operations for the three- and nine-month periods ended June 30, 2004, are not indicative of expected results of operations for the fiscal year ending September 30, 2004.

#### *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, 2003. As described in our Annual Report on Form 10-K, our utility depreciation rates approved by the various regulatory commissions included a component that allowed us to recover the cost of removing our assets. Historically, we recorded the associated obligation as a component of accumulated depreciation. This classification was consistent with others in the industry. Beginning in the second quarter of fiscal 2004, we are classifying our regulatory cost of removal obligation as a regulatory liability on the balance sheet. Additionally, for purposes of our September 30, 2003 information presented in this report, we reclassified from accumulated depreciation to regulatory liabilities a total of \$108.4 million in regulatory cost of removal accruals at September 30, 2003, of which \$102.4 million was a long-term regulatory liability. These reclassifications do not impact our financial position, results of operations, cash flows or ability to satisfy our financial covenants contained in our various credit agreements as of June 30, 2004 and September 30, 2003.

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We have designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings when the hedged volumes are sold.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

This designation is expected to partially reduce the amount of volatility in our condensed consolidated income statement and better reflect the economics of this type of transaction.

***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, restricted stock and performance-based stock 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.

As permitted by Statement of Financial Accounting Standard (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.

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 (loss) and earnings (loss) per share for the three months and nine months ended June 30, 2004 and 2003 would have been impacted as shown in the following table:

	<u>Three Months Ended June 30</u>		<u>Nine Months Ended June 30</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	(In thousands, except per share data)			
Net income (loss) — as reported . . . . .	\$4,765	\$ (201)	\$92,611	\$74,124
Restricted stock compensation expense included in income, net of tax . . . . .	384	14	580	187
Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of taxes . . . . .	<u>(651)</u>	<u>(271)</u>	<u>(1,428)</u>	<u>(884)</u>
Net income (loss) — pro forma . . . . .	<u>\$4,498</u>	<u>\$ (458)</u>	<u>\$91,763</u>	<u>\$73,427</u>
Earnings per share:				
Basic earnings per share — as reported . . . . .	<u>\$ 0.09</u>	<u>\$(0.00)</u>	<u>\$ 1.79</u>	<u>\$ 1.66</u>
Basic earnings per share — pro forma . . . . .	<u>\$ 0.09</u>	<u>\$(0.01)</u>	<u>\$ 1.77</u>	<u>\$ 1.64</u>
Diluted earnings per share — as reported . . . . .	<u>\$ 0.09</u>	<u>\$(0.00)</u>	<u>\$ 1.78</u>	<u>\$ 1.65</u>
Diluted earnings per share — pro forma . . . . .	<u>\$ 0.09</u>	<u>\$(0.01)</u>	<u>\$ 1.76</u>	<u>\$ 1.64</u>

No option grants have occurred under the Long-Term Stock Plan for the Mid-States Division since that entity was acquired in 1997. Due to the limited activities of that plan, the pro forma effect of applying SFAS 123 would have had less than a \$0.01 per diluted share effect on earnings per share for the three and

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

nine months ended June 30, 2004 and 2003, or \$160 and \$416 for the three months ended June 30, 2004 and 2003 and \$922 and \$1,922 for the nine months ended June 30, 2004 and 2003.

***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. Significant regulatory assets and liabilities as of June 30, 2004 and September 30, 2003 included the following:

	<u>June 30, 2004</u>	<u>September 30, 2003</u>
(In thousands)		
<b>Regulatory assets:</b>		
Deferred gas costs .....	\$ —	\$ 308
Merger and integration costs, net .....	17,536	23,380
Deferred MVG operating expenses .....	5,806	4,645
Environmental costs .....	4,056	4,057
Other .....	<u>3,511</u>	<u>2,509</u>
	<u>\$ 30,909</u>	<u>\$ 34,899</u>
<b>Regulatory liabilities:</b>		
Regulatory cost of removal obligation .....	\$110,363	\$108,405
Deferred gas costs .....	33,523	—
Deferred income taxes, net .....	<u>1,883</u>	<u>1,883</u>
	<u>\$145,769</u>	<u>\$110,288</u>

Currently authorized rates do not include a return on our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are amortized on a straight-line basis over estimated useful lives ranging from 7 to 20 years. These costs will have been substantially amortized by December 2004. 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, 2004 and 2003:

	Three Months Ended June 30		Nine Months Ended June 30	
	2004	2003	2004	2003
	(In thousands)			
Net income (loss) .....	\$ 4,765	\$ (201)	\$92,611	\$74,124
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of \$(270) and \$808 for the three months ended June 30, 2004 and 2003 and net of tax expense of \$654 and \$319 for the nine months ended June 30, 2004 and 2003 .....	(441)	1,318	1,067	519
Unrealized gains on commodity hedging transactions, net of tax expense of \$829 for the three and nine months ended June 30, 2004 .....	1,353	—	1,353	—
Unrealized losses on interest rate hedging transactions, net of tax benefit of \$2,684 for the three and nine months ended June 30, 2004 .....	(4,377)	—	(4,377)	—
Comprehensive income .....	<u>\$ 1,300</u>	<u>\$1,117</u>	<u>\$90,654</u>	<u>\$74,643</u>

Accumulated other comprehensive income consists of unrealized holding gains and losses associated with certain available-for-sale investments and unrealized gains and losses associated with commodity and interest rate hedging transactions. In connection with the pending acquisition of the TXU Gas operations, the Company entered into Treasury interest rate locks associated with \$675.0 million of long-term debt to be issued in connection with the acquisition (see Note 5).

***Recent Accounting Developments***

In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) 46, *Consolidation of Variable Interest Entities, An Interpretation of Accounting Research Bulletin No. 51*. The primary objectives of FIN 46 are to provide guidance on how to identify entities for which control is achieved through means other than through voting rights (variable interest entities (VIE)) and how to determine when to consolidate and which business enterprises should consolidate the VIE. The adoption of this interpretation did not have a material impact on our financial position, results of operations or net cash flows because we are not currently a beneficiary of a VIE.

During 2003, the Emerging Issues Task Force (the Task Force) added to its agenda Emerging Issues Task Force (EITF) Issue 03-01, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*, to address the meaning of “other-than-temporary” impairment and its application to certain investments carried at cost. In November 2003, the Task Force developed new disclosure requirements concerning unrealized losses on available-for-sale debt and equity securities accounted for under SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*, which will be applicable to us beginning with our fiscal 2004 Annual Report on Form 10-K.

In December 2003, the FASB issued SFAS 132 (revised), *Employers’ Disclosures about Pensions and Other Postretirement Benefits*. These revisions require additional disclosures in annual reports on Form 10-K concerning the assets, obligations, cash flows and net periodic-benefit cost of defined-benefit pension plans and other defined-benefit postretirement plans. Additionally, the statement now requires interim-period disclosures regarding net periodic pension cost and employer contributions. The annual disclosures will become fully

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

effective for fiscal years ending after June 15, 2004, and the interim-period disclosures were effective for interim periods beginning after December 15, 2003. We have adopted the interim-period disclosures, which are contained in Note 8, and will adopt the annual disclosures beginning with our fiscal 2004 Annual Report on Form 10-K.

In January 2004, the FASB issued FASB Staff Position FAS 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, which permits a plan sponsor to defer recognizing the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) in accounting for its plan under SFAS 106 and in providing disclosures related to the plan required by SFAS 132 (revised). We elected to recognize the provisions of the Act, beginning with the second quarter of fiscal 2004, which reduced our accumulated postretirement benefit obligation and our net postretirement benefit obligation costs by \$4.1 million based upon calculations prepared by our independent actuaries. The total income statement impact for fiscal 2004 will approximate \$2.3 million, as a portion of this benefit will be capitalized.

### 3. Acquisitions

#### *TXU Gas Company*

On June 17, 2004, we entered into a definitive agreement with TXU Gas Company (TXU Gas) to acquire the natural gas distribution and pipeline operations of TXU Gas.

The TXU Gas operations we are acquiring 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. TXU Gas provides gas distribution services to over 1.4 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. TXU Gas owns and operates a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas. The acquisition would increase the number of customers we serve in our distribution business to over 3.1 million.

The purchase price, excluding transaction costs, for the acquisition is \$1.925 billion, which is payable in cash. The price is subject to adjustment if at the time of closing the working capital of TXU Gas is less or more than approximately \$121 million. The price is also subject to increase by the amount of any capital expenditures made by TXU Gas prior to closing that exceed its budgeted amounts. We are not assuming any indebtedness in the transaction. TXU Gas has agreed to repay or redeem all of its existing indebtedness and its preferred stock and to retain or pay certain other liabilities under the terms of the acquisition agreement.

We have received a commitment from a third party financial institution, subject to customary conditions, to provide a senior unsecured credit facility in the amount of \$1.925 billion to finance, or backstop the issuance of commercial paper to finance, this acquisition. The bridge financing facility will mature 364 days after the closing date of the acquisition. The commitment is subject to the absence of a material adverse effect on our business and assets, after giving effect to the acquisition, the absence of any new adverse information affecting us, TXU Gas or the acquisition that would materially impair the syndication of the bridge financing facility and other specified conditions. The amount of the bridge financing facility will be reduced to the extent we obtain acquisition financing prior to the closing of the acquisition. As further described in Note 12, in July 2004, we sold 9,939,393 common shares, which generated net proceeds of \$236.2 million before legal, accounting and other offering costs, that will be used to reduce the amount we intend to borrow under this facility. We intend to seek long-term debt and additional common equity financings to refinance the bridge financing facility.

We expect the acquisition to close by the end of the calendar year 2004; however, this acquisition is subject to the satisfaction of several conditions, including regulatory approvals in three states and clearance by antitrust authorities. The 30-day waiting period under the Hart-Scott-Rodino Act expired August 2, 2004 with

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

no inquiries from the Justice Department or Federal Trade Commission. In addition, the Virginia State Corporation Commission issued an order on August 6, 2004 approving the short-term debt financing for the acquisition, while regulatory approvals from the state regulatory commissions in Iowa and Missouri are pending. If we have not obtained our three state regulatory approvals by December 31, 2004 and the other conditions to closing have been satisfied, TXU Gas may terminate the agreement and require us to pay \$15 million in full satisfaction of our obligations under the agreement. In addition, we or TXU Gas may terminate the agreement if the applicable closing conditions are not satisfied or waived by December 31, 2004. The closing date may be extended for up to 90 days to the extent required for TXU Gas to repair any material casualty loss incurred before closing.

***ComFurT Gas Inc.***

Effective March 1, 2004, we completed the acquisition of the natural gas distribution assets of ComFurT Gas Inc., a privately held natural gas utility and propane distributor based in Buena Vista, Colorado, for approximately \$2.0 million in cash. This company served approximately 1,800 natural gas utility customers. The acquisition enabled us to expand our contiguous service area in our Colorado-Kansas division. Unaudited pro forma results of the Company and ComFurT have not been presented as the acquisition was not material to our financial position or results of operations.

**4. Goodwill and Intangible Assets**

Goodwill and intangible assets are comprised of the following as of June 30, 2004 and September 30, 2003.

	June 30, 2004	September 30, 2003
(In thousands)		
Goodwill . . . . .	\$271,467	\$268,469
Intangible assets . . . . .	4,377	5,030
Total . . . . .	\$275,844	\$273,499

The following presents our goodwill balance allocated by segment and changes in our balance for the nine months ended June 30, 2004:

	Utility Segment	Natural Gas Marketing Segment	Other Nonutility Segment	Total
(In thousands)				
Balance as of September 30, 2003 . . . . .	\$233,741	\$22,600	\$12,128	\$268,469
Acquisition . . . . .	1,250	—	—	1,250
Refinements to purchase price . . . . .	2,644	(896)	—	1,748
Balance as of June 30, 2004 . . . . .	\$237,635	\$21,704	\$12,128	\$271,467

During the second quarter of fiscal 2004, we completed our annual goodwill impairment assessment. Based upon the assessment performed, our goodwill was not considered to be 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 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

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

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.

The following table shows the fair values of our risk management assets and liabilities by segment at June 30, 2004 and September 30, 2003:

	<u>Utility</u>	<u>Natural Gas Marketing</u> (In thousands)	<u>Total</u>
<b>June 30, 2004:</b>			
Assets from risk management activities, current . . . . .	\$ 789	\$ 8,764	\$ 9,553
Assets from risk management activities, noncurrent . . . . .	—	732	732
Liabilities from risk management activities, current . . . . .	(8,227)	(7,403)	(15,630)
Liabilities from risk management activities, noncurrent . . . . .	—	(1,598)	(1,598)
Net assets (liabilities) . . . . .	<u>\$(7,438)</u>	<u>\$ 495</u>	<u>\$(6,943)</u>
<b>September 30, 2003:</b>			
Assets from risk management activities, current . . . . .	\$ 202	\$ 22,057	\$ 22,259
Assets from risk management activities, noncurrent . . . . .	—	1,699	1,699
Liabilities from risk management activities, current . . . . .	(7,941)	(12,849)	(20,790)
Liabilities from risk management activities, noncurrent . . . . .	—	(763)	(763)
Net assets (liabilities) . . . . .	<u>\$(7,739)</u>	<u>\$ 10,144</u>	<u>\$ 2,405</u>

***Utility Hedging Activities***

We use a combination of storage, fixed-price physical contracts and fixed-price financial contracts to protect us and our customers against unusually large winter-period gas price increases. For the 2003-2004 heating season, we hedged between 50 and 55 percent of our winter flowing gas requirements at a weighted average cost of approximately \$5.36 per MCF. These derivative financial instruments are marked to market pursuant to SFAS 133, *Accounting for Derivative Financial Instruments and Hedging Activities*. Because these costs will ultimately be recovered through our rates, current-period changes in the assets and liabilities from risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71 and recognized in purchased gas cost in the income statement when the related costs are recovered through our rates. Accordingly, there is no earnings impact as a result of the use of these financial instruments in our utility segment.

In June 2001, we purchased a three-year weather-insurance policy with an option to cancel the third year of coverage. The insurance covered our Texas and Louisiana operations to protect against weather that was at least 7 percent warmer than normal for the entire heating season of October through March, beginning with the 2001-2002 heating season. The prepaid cost of the three-year policy was \$13.2 million and was amortized over the appropriate heating seasons based on heating degree days. In the third quarter of fiscal 2003, we cancelled this policy, primarily as a result of rate relief in Louisiana and prospects for weather normalization adjustments in Texas. During the three months and nine months ended June 30, 2003, we recognized amortization expense of \$0.6 million and \$5.0 million. However, we did not collect under this policy because weather was not at least 7 percent warmer than normal.

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

#### *Nonutility Hedging Activities*

Our natural gas marketing hedging activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, and we manage our exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date. The use of these contracts is subject to our risk management policies, which are monitored for compliance on a daily basis.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, 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.

Under SFAS 133, natural gas inventory is the hedged item in a fair-value hedge and is marked to market on a monthly basis using the inside FERC (iFERC) price at the end of each month. Changes in fair value are recognized as unrealized gains and losses in the period of change. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our condensed consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our storage gas contracts 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 difference in 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. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

Similar to our inventory position, we attempt to mitigate substantially all of the commodity price risk associated with our fixed-price contracts with minimum volume requirements through the use of various offsetting derivatives. Prior to April 1, 2004, these derivatives were not designated as hedges under SFAS 133 because they naturally locked in the economic gross profit margin at the time we enter into the contract. The fixed-price forward and offsetting derivative contracts were marked to market each month with changes in fair value recognized as unrealized gains and losses in our condensed consolidated statement of income. The unrealized gains and losses are realized in the period in which we fulfill the requirements of the fixed-price contract and the derivatives are settled. To the extent that the unrealized gains and losses of the fixed-price forward contracts and the offsetting derivatives do not offset exactly, our earnings will experience some volatility. At delivery, the gains and losses on the fixed-price contracts were offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We have designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings when the hedged volumes are sold.

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

This designation is expected to partially reduce the amount of volatility in our condensed consolidated income statement and more accurately reflect the economics of this type of transaction.

For the three and nine months ended June 30, 2004, the increase in the deferred hedging gain in accumulated other comprehensive income was attributable to the initiation of cash flow hedge accounting treatment described above and increases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, partially offset by the reclassification of \$2.6 million in net deferred hedge gains to net income as derivatives matured according to their terms. The net deferred hedge losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The deferred hedging gain as of June 30, 2004 is expected to be substantially recognized within the next six months.

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, 2004, AEH had a net open position (including existing storage) of 0.4 Bcf.

On January 1, 2003, we recorded a cumulative effect of a change in accounting principle to reflect a change in the way we account for our storage and transportation contracts. Previously we accounted for those contracts under EITF 98-10, *Accounting for Energy Trading and Risk Management Activities*, which required us to record estimated future gains on our storage and transportation contracts at the time we entered into the contracts and to mark those contracts to market value each month. Effective January 1, 2003, we no longer marked those contracts to market. As a result, we expensed \$7.8 million, net of applicable income tax benefit, as a cumulative effect of a change in accounting principle.

#### *Treasury Activities*

In June 2004, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of \$675 million of long-term debt. This long-term debt will be used to refinance a portion of the 364-day bridge financing facility that will be used to finance the TXU Gas acquisition on an interim basis, as described in Note 3. The Treasury locks are scheduled to terminate on December 31, 2004; however, we have the ability to terminate the locks at our discretion within 60 days of December 31, 2004.

We have designated these Treasury locks as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury locks will be recorded as a component of accumulated other comprehensive income. Unrealized gains will be recorded when interest rates increase and unrealized losses will be recorded when interest rates decline. Upon termination of the Treasury lock agreements, the unrealized gain or loss will be recognized over the life of the related financing arrangement. Any gains or losses arising from ineffectiveness will be recognized into earnings as incurred. At June 30, 2004, we recorded deferred hedging losses of \$4.4 million, net of tax, as a component of accumulated other comprehensive income related to these Treasury locks due to a decline in the 5 and 10 year Treasury rates between the inception of the Treasury locks and June 30, 2004.

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**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**6. Debt**

*Long-Term Debt*

Long-term debt at June 30, 2004 and September 30, 2003 consisted of the following:

	<b>June 30, 2004</b>	<b>September 30, 2003</b>
(In thousands)		
Unsecured 10% Notes, due 2011 . . . . .	\$ 2,303	\$ 2,303
Unsecured 7.375% Senior Notes, due 2011 . . . . .	350,000	350,000
Unsecured 5.125% Senior Notes, due 2013 . . . . .	250,000	250,000
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	17,000
Series P, 10.43% due 2013 . . . . .	11,250	13,750
Series Q, 9.75% due 2020 . . . . .	16,000	17,000
Series R, 11.32% due 2004 . . . . .	—	2,160
Series T, 9.32% due 2021 . . . . .	18,000	18,000
Series U, 8.77% due 2022 . . . . .	20,000	20,000
Series V, 7.50% due 2007 . . . . .	4,167	6,733
Rental property, propane and other term notes due in installments through 2013 . . . . .	10,464	6,317
Total long-term debt . . . . .	869,184	873,263
Less current maturities . . . . .	(5,918)	(9,345)
	<b>\$863,266</b>	<b>\$863,918</b>

Most of the First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1988, may not exceed the sum of accumulated net income for periods after December 31, 1988, plus \$15.0 million. At June 30, 2004, approximately \$129.1 million of retained earnings were unrestricted with respect to the payment of dividends. We were in compliance with all of our debt covenants as of June 30, 2004.

*Short-Term Debt*

At June 30, 2004, there were no short-term amounts outstanding under our commercial paper program or bank credit facilities. At September 30, 2003, short-term debt consisted of \$118.6 million of commercial paper. No amounts were outstanding under our bank credit facilities at September 30, 2003.

*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

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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*

We have two short-term committed credit facilities totaling \$368.0 million, one of which is an unsecured facility for \$350.0 million that bears interest at the Eurodollar rate plus 0.625 percent and serves as a backup liquidity facility for our commercial paper program. In July 2004, we renewed this facility on substantially the same terms as those of the existing facility, and it will expire in January 2005. We expect that this facility will be resized and renewed following the closing of the acquisition of the TXU Gas operations. We have a second unsecured facility in place for \$18.0 million that bears interest at the Fed Funds rate plus 0.5 percent and is used for working-capital purposes. At June 30, 2004, there were no amounts outstanding under these credit facilities. These credit facilities are negotiated at least annually. On April 1, 2004, the \$18.0 million working-capital credit facility was renewed for an additional 12 months on terms substantially similar to those of the prior facility.

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 \$350.0 million credit facility to maintain a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2004, our total-debt-to-total-capitalization ratio, as defined, was 50 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our \$350.0 million credit facility are subject to adjustment depending upon our credit ratings. We and our lead bank plan to amend this facility's terms prior to closing the TXU Gas acquisition to accommodate the expected increase in our debt to capital ratio that will result from the acquisition.

#### *Uncommitted Credit Facilities*

AEM has a \$250.0 million uncommitted-demand working capital credit facility that bears interest at the Eurodollar rate plus 2.5 percent and expires on March 31, 2005. Effective October 1, 2003, with the reorganization of our natural gas marketing segment, AEM became the borrower under the credit facility, and AEH became the sole guarantor of the facility. At June 30, 2004, no amounts were outstanding under this credit facility. AEM letters of credit totaling \$74.2 million reduced the amount available in accordance with the terms of the facility. 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 \$57.8 million at June 30, 2004.

We also have 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, 2004, but Atmos Energy Corporation (AEC) letters of credit reduced the amount available by \$3.5 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.

In addition, AEM has a \$100.0 million intercompany credit facility with AEC through AEH for its nonutility business which bears interest at the Eurodollar 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. This credit facility was renewed effective July 1, 2004 on substantially the same terms as those of the existing facility and has been approved by our state regulators through December 31, 2004. However, there is no assurance that our

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

regulators will approve our use of this credit facility after that time. At June 30, 2004, \$20.0 million was outstanding under this facility.

**7. Earnings Per Share**

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

	<u>For the Three Months</u> <u>Ended June 30</u>		<u>For the Nine Months</u> <u>Ended June 30</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	(In thousands, except per share amounts)			
Income (loss) before cumulative effect of accounting change .....	\$ 4,765	\$ (201)	\$92,611	\$81,897
Cumulative effect of accounting change, net of income tax benefit.....	<u>—</u>	<u>—</u>	<u>—</u>	<u>(7,773)</u>
Net income (loss) .....	<u>\$ 4,765</u>	<u>\$ (201)</u>	<u>\$92,611</u>	<u>\$74,124</u>
Denominator for basic income per share — weighted average common shares .....	52,220	45,997	51,788	44,679
Effect of dilutive securities:				
Restricted stock.....	258	—	258	122
Stock options .....	<u>139</u>	<u>—</u>	<u>120</u>	<u>78</u>
Denominator for diluted income per share — weighted average common shares .....	<u>52,617</u>	<u>45,997</u>	<u>52,166</u>	<u>44,879</u>
Income (loss) per share — basic:				
Before cumulative effect of accounting change ....	\$ 0.09	\$ (0.00)	\$ 1.79	\$ 1.83
Cumulative effect of accounting change, net of income tax benefit.....	<u>—</u>	<u>—</u>	<u>—</u>	<u>(.17)</u>
Net income (loss) per share .....	<u>\$ 0.09</u>	<u>\$ (0.00)</u>	<u>\$ 1.79</u>	<u>\$ 1.66</u>
Income (loss) per share — diluted:				
Before cumulative effect of accounting change ....	\$ 0.09	\$ (0.00)	\$ 1.78	\$ 1.82
Cumulative effect of accounting change, net of income tax benefit.....	<u>—</u>	<u>—</u>	<u>—</u>	<u>(.17)</u>
Net income (loss) per share .....	<u>\$ 0.09</u>	<u>\$ (0.00)</u>	<u>\$ 1.78</u>	<u>\$ 1.65</u>

There were approximately 84,000 options and approximately 122,000 shares of restricted stock as of June 30, 2003 that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2003 as their inclusion in the computation would be anti-dilutive.

There were no options excluded from the computation of diluted earnings per share for the three months ended June 30, 2004 as the exercise price for all options was less than the average market price of the common stock during that period. There were 577,500 out-of-the-money options excluded from the computation of diluted earnings per share for the three months ended June 30, 2003 as their exercise price was greater than the average market price of the common stock during that period.

There were 3,000 and 577,500 out-of-the-money options excluded from the computation of diluted earnings per share for the nine months ended June 30, 2004 and 2003 as their exercise price was greater than the average market price of the common stock during that period.

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**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**8. Interim Pension and Other Postretirement Benefit Plan Information**

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended June 30, 2004 and 2003 are presented below. The 2004 amounts reflect the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) beginning in the second quarter of fiscal 2004.

	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	(In thousands)			
Components of net periodic pension cost:				
Service cost .....	\$ 2,433	\$ 2,060	\$1,405	\$1,476
Interest cost .....	6,004	5,834	1,751	2,269
Expected return on assets .....	(7,524)	(5,988)	(396)	(253)
Amortization of transition asset .....	24	24	378	378
Amortization of prior service cost .....	(2)	35	96	92
Amortization of actuarial loss .....	<u>2,018</u>	<u>632</u>	<u>—</u>	<u>444</u>
Net periodic pension cost .....	<u>\$ 2,953</u>	<u>\$ 2,597</u>	<u>\$3,234</u>	<u>\$4,406</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, 2004 and 2003 are as follows:

	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	(In thousands)			
Components of net periodic pension cost:				
Service cost .....	\$ 7,299	\$ 6,180	\$ 4,535	\$ 4,428
Interest cost .....	18,012	17,502	5,605	6,807
Expected return on assets .....	(22,572)	(17,964)	(1,127)	(759)
Amortization of transition asset .....	72	72	1,134	1,134
Amortization of prior service cost .....	(6)	105	288	276
Amortization of actuarial loss .....	<u>6,054</u>	<u>1,896</u>	<u>635</u>	<u>1,332</u>
Net periodic pension cost .....	<u>\$ 8,859</u>	<u>\$ 7,791</u>	<u>\$11,070</u>	<u>\$13,218</u>

A portion of these costs is capitalized into our utility rate base, as these costs are recoverable through our gas utility rates. Costs that are not capitalized are recorded as a component of operating expense.

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2004 and 2003 are as follows:

	<u>Pension Benefits</u>		<u>Other Benefits</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
Discount rate .....	6.00%	6.00%	6.00%	6.00%
Rate of compensation increase .....	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets .....	9.00%	9.00%	5.30%	5.30%

In our Annual Report on Form 10-K for the year ended September 30, 2003, we disclosed that anticipated additional voluntary contributions ranging from \$0 to \$15 million during fiscal 2004 may be necessary to keep the Atmos Energy Corporation Pension Account Plan (the Pension Account Plan) 100 percent funded on an accumulated benefit obligation (ABO) basis. We did not contribute to our pension

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

plan during the nine months ended June 30, 2004 and we do not anticipate voluntarily contributing to the Pension Account Plan during the remainder of fiscal 2004.

#### 9. Commitments and Contingencies

##### *Litigation*

##### *Colorado-Kansas Division*

On September 23, 1999, a suit was filed in the District Court of Stevens County, Kansas, by Quinque Operating Company, Tom Boles and Robert Ditto against more than 200 companies in the natural gas industry, including us and our Colorado-Kansas Division. The plaintiffs, who purport to represent a class consisting of gas producers, royalty owners, overriding royalty owners, working interest owners and state taxing authorities, allege that the defendants have underpaid royalties on gas taken from wells situated on nonfederal and non-Indian lands throughout the United States and offshore waters, predicated upon allegations that the defendants' gas measurements are simply inaccurate and that the defendants failed to comply with applicable regulations and industry standards over the last 25 years. Although the plaintiffs do not specifically allege an amount of damages, they contend that this suit is brought to recover billions of dollars in revenues that the defendants have allegedly unlawfully diverted from the plaintiffs to themselves. On April 10, 2000, this case was consolidated for pretrial proceedings with other similar pending litigation in federal court in Wyoming in which we are also a defendant, along with more than 200 other defendants, in the case of *In Re Natural Gas Royalties Qui Tam Litigation*. In January 2001, the federal court elected to remand this case to the Kansas state court. A reconsideration of remand was filed, but it was denied. The state court now has jurisdiction over this proceeding and has issued a preliminary case management order. On April 10, 2003, the court denied the plaintiffs' motion to certify this proceeding as a class action, which ruling was appealed by the plaintiffs. The court did allow the plaintiffs to file an amended complaint, which is somewhat narrower in scope than the original complaint. There have since been no material developments in this case. We continue to believe that the plaintiffs' claims are lacking in merit, and we intend to continue to vigorously defend this action. While the results of this litigation cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial condition, results of operations or net cash flows.

##### *Texas Division*

On February 13, 2002, a suit was filed in the 287th District Court of Parmer County, Texas, by Anderson Brothers, a Partnership, against Atmos Energy Corporation, *et al.* The plaintiffs' claims arise out of an alleged breach of contract by us and by a number of our divisions and subsidiaries concerning the sale of natural gas used in irrigation activities since 1998 and an alleged violation of the Texas Agricultural Gas Users Act of 1985. We have reached a tentative settlement with the plaintiffs' attorneys in this case. A fairness hearing will be held on the proposed settlement agreement on August 24, 2004. The settlement agreement must be approved by the court and then by the plaintiffs as a class, which is expected by the end of October 2004. We believe the final outcome of this litigation will not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a 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, pending in the District Court of Lubbock County, Texas, 72nd Judicial District. In this case, we are seeking to collect our receivable related to approximately 5.0 Bcf of natural gas that we believe was not delivered. We have settled a portion of our claims with the parties and will continue to pursue recovery of the remaining claims, which we believe are fully recoverable. We are proceeding with discovery in this case, which has been set for trial in 2005.

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

#### *United Cities Propane Gas, Inc.*

United Cities Propane Gas, Inc., one of our wholly-owned subsidiaries, is a party to an action filed in June 2000 that is pending in the Circuit Court of Sevier County, Tennessee. The plaintiffs' claims arise out of injuries alleged to have been caused by a low-level propane explosion. The plaintiffs seek to recover damages of \$13.0 million. Discovery activities continue in this case. We have denied any liability, and we intend to vigorously defend against the plaintiffs' claims. This case has been set for trial on November 1, 2004. While the results of this litigation cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a party to other litigation and claims that arise in the ordinary course of our business. While the results of such litigation and claims cannot be predicted with certainty, 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.

#### *Environmental Matters*

##### *Manufactured Gas Plant Sites*

We are the owner or previous owner of manufactured gas plant sites in Johnson City and Bristol, Tennessee, and Hannibal, Missouri, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. Under current environmental protection laws and regulations, we may be responsible for response actions with respect to such materials if response actions are necessary.

United Cities Gas Company and the Tennessee Department of Environment and Conservation (TDEC) entered into a consent order effective January 23, 1997, to facilitate the investigation, removal and remediation of the Johnson City site. Prior to our merger with United Cities Gas Company in July 1997, United Cities Gas Company began the implementation of the consent order in the first quarter of fiscal 1997, which we continued through June 30, 2004. The investigative phase of the work at the site has been completed, and an interim removal action was completed in June 2001. We installed four groundwater monitoring wells at the site in 2002 and have submitted the analytical results to the TDEC. We have completed a risk assessment report that has been approved by the TDEC. Finally, we have completed a feasibility study for this site, which was submitted to the TDEC in October 2003. The feasibility study recommends a remedial action that will limit the use of and access to the impacted soil, cap the site with the addition of a clay fill and geosynthetic liner, and groundwater monitoring for a period of up to 30 years. The estimated cost of the proposed remedial action is \$1.5 million, which is comprised primarily of operating and maintenance costs that would be associated with a groundwater monitoring project. The Tennessee Regulatory Authority granted us permission to defer, until our next rate case in Tennessee, all costs incurred in Tennessee in connection with state and federally mandated environmental control requirements.

In March 2002, the TDEC contacted us about conducting an investigation at a former manufactured gas plant located in Bristol, Tennessee. We agreed to perform a preliminary investigation at the site, which we completed in June 2002. The investigation identified manufactured gas plant residual materials in the soil beneath the site, and we have proposed performing a focused removal action to remove any such residuals. The TDEC has requested that the focused removal action be conducted pursuant to a voluntary agreement. On April 13, 2004, we entered into a voluntary consent agreement with the TDEC for the performance of the removal action and anticipate completing such removal action later this year.

On July 22, 1998, we entered into an Abatement Order on Consent with the Missouri Department of Natural Resources to address the former manufactured gas plant located in Hannibal, Missouri. We agreed to perform a removal action and a subsequent site evaluation and to reimburse the response costs incurred by the

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

state of Missouri in connection with the property. The removal action was conducted and completed in August 1998, and the site-evaluation field work was conducted in August 1999. A risk assessment for the site has been approved by the Missouri Department of Natural Resources. In preparation for the risk assessment, we executed and recorded certain site-use limitations, including restricting use of the site to commercial and industrial purposes and prohibiting the withdrawal of groundwater for use as drinking water. In addition, we intend to grade the site and install a geosynthetic liner over the surface of the site by the end of calendar 2004.

In 1995, United Cities Gas Company entered into an agreement with a third party to resolve its share of the costs of additional investigations and environmental-response actions for soil contamination at a former manufactured gas plant in Keokuk, Iowa. However, the extent of groundwater contamination at the site, if any, which is not covered by the agreement, has yet to be determined.

As of June 30, 2004, we had incurred costs of approximately \$1.7 million for the investigations of the Johnson City and Bristol, Tennessee, and Hannibal, Missouri, sites and had a remaining accrual relating to these sites of \$0.2 million, which is recorded as a component of other current liabilities.

We are a party to other environmental matters and claims that arise out of our ordinary business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or net cash flows because we believe that the expenditures related to such response actions will be recovered through rates, shared with other parties or adequately covered by insurance.

#### *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, 2004, AEM is committed to purchase 48.8 Bcf within one year and 1.1 Bcf within one to three years under indexed contracts. AEM is committed to purchase 0.6 Bcf within one year under fixed-price contracts, with prices ranging from \$4.08 to \$6.47. Purchases under these contracts totaled \$283.5 million and \$320.0 million for the three months ended June 30, 2004 and 2003 and \$981.5 and \$1,118.6 million for the nine months ended June 30, 2004 and 2003.

Our utility segment maintains supply contracts with several vendors, generally for 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.

#### *Other*

During fiscal 2003, the Internal Revenue Service initiated a routine examination of our fiscal 1999, 2000 and 2001 tax returns. We believe all material tax items have been accrued related to the years under audit.

### **10. 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. Due to minimal receivables, the credit risk for our other nonutility segment is not significant.

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

This diversification in AEM's customers helps mitigate its 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 counterparty nonperformance.

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 based on external ratings provided by Moody's Investor Service Inc. and/or Standard & Poor's Rating Service, a Division of the McGraw-Hill Companies, Inc. For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The table below shows the percentages related to the investment ratings as of June 30, 2004 and September 30, 2003. As indicated below, a majority of AEM's customers are rated as investment grade.

	<b>June 30, 2004</b>	<b>September 30, 2003</b>
Investment grade . . . . .	53%	59%
Non-investment grade . . . . .	47%	41%
Total . . . . .	100%	100%

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, 2004. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's Rating Group; 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.

	<b>At June 30, 2004</b>			<b>Consolidated</b>
	<b>Utility Segment<sup>(1)</sup></b>	<b>Natural Gas Marketing Segment</b>	<b>Other Nonutility Segment</b>	
	<b>(In thousands)</b>			
Investment grade counterparties . . . . .	\$789	\$9,147	\$—	\$ 9,936
Non-investment grade counterparties . . . . .	—	349	—	349
	\$789	\$9,496	\$—	\$10,285

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

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**11. 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 1.7 million residential, commercial, public-authority and industrial customers through our six 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 18 states. Finally, we construct electric power-generating plants and associated facilities to meet peak load demands and lease or sell them to municipalities and industrial customers.

Our operations are divided into three 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 and
- The other nonutility segment, which includes all of our other nonutility operations.

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. The accounting policies of the segments are the same as those described in Note 2 to our Annual Report on Form 10-K for the year ended September 30, 2003. We evaluate performance based on net income or loss of the respective operating units. Summarized income statements by segment are shown in the following tables.

	<u>For the Three Months Ended June 30, 2004</u>				
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)				
Operating revenues from external parties . . . . .	\$255,986	\$288,809	\$1,263	\$ —	\$546,058
Intersegment revenues . . . . .	<u>266</u>	<u>75,530</u>	<u>4,947</u>	<u>(80,743)</u>	<u>—</u>
	256,252	364,339	6,210	(80,743)	546,058
Purchased gas cost . . . . .	<u>163,093</u>	<u>352,708</u>	<u>3,150</u>	<u>(80,385)</u>	<u>438,566</u>
Gross profit . . . . .	93,159	11,631	3,060	(358)	107,492
Operating expenses . . . . .	<u>79,967</u>	<u>4,784</u>	<u>1,639</u>	<u>(358)</u>	<u>86,032</u>
Operating income . . . . .	13,192	6,847	1,421	—	21,460
Miscellaneous income (expense)	1,668	178	1,637	(1,296)	2,187
Interest charges . . . . .	<u>16,119</u>	<u>411</u>	<u>777</u>	<u>(1,296)</u>	<u>16,011</u>
Income (loss) before income taxes . . . . .	(1,259)	6,614	2,281	—	7,636
Income tax expense (benefit) . . . . .	<u>(711)</u>	<u>2,664</u>	<u>918</u>	<u>—</u>	<u>2,871</u>
Net income (loss) . . . . .	<u>\$ (548)</u>	<u>\$ 3,950</u>	<u>\$1,363</u>	<u>\$ —</u>	<u>\$ 4,765</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

	<b>For the Three Months Ended June 30, 2003</b>				<b>Consolidated</b>
	<b>Utility</b>	<b>Natural Gas Marketing</b>	<b>Other Nonutility</b>	<b>Eliminations</b>	
			<b>(In thousands)</b>		
Operating revenues from external parties . . . . .	\$245,741	\$240,760	\$1,969	\$ —	\$488,470
Intersegment revenues . . . . .	<u>257</u>	<u>134,072</u>	<u>1,716</u>	<u>(136,045)</u>	<u>—</u>
	245,998	374,832	3,685	(136,045)	488,470
Purchased gas cost . . . . .	<u>161,426</u>	<u>367,395</u>	<u>467</u>	<u>(135,882)</u>	<u>393,406</u>
Gross profit . . . . .	84,572	7,437	3,218	(163)	95,064
Operating expenses . . . . .	<u>78,306</u>	<u>1,375</u>	<u>1,490</u>	<u>(163)</u>	<u>81,008</u>
Operating income . . . . .	6,266	6,062	1,728	—	14,056
Miscellaneous income (expense) . . . . .	1,347	430	662	(1,753)	686
Interest charges . . . . .	<u>16,235</u>	<u>662</u>	<u>898</u>	<u>(1,753)</u>	<u>16,042</u>
Income (loss) before income taxes . . . . .	(8,622)	5,830	1,492	—	(1,300)
Income tax expense (benefit) . . . . .	<u>(4,005)</u>	<u>2,314</u>	<u>592</u>	<u>—</u>	<u>(1,099)</u>
Net income (loss) . . . . .	<u>\$ (4,617)</u>	<u>\$ 3,516</u>	<u>\$ 900</u>	<u>\$ —</u>	<u>\$ (201)</u>

	<b>For the Nine Months Ended June 30, 2004</b>				<b>Consolidated</b>
	<b>Utility</b>	<b>Natural Gas Marketing</b>	<b>Other Nonutility</b>	<b>Eliminations</b>	
			<b>(In thousands)</b>		
Operating revenues from external parties . . . . .	\$1,424,180	\$ 999,135	\$ 3,844	\$ —	\$2,427,159
Intersegment revenues . . . . .	<u>842</u>	<u>256,251</u>	<u>16,648</u>	<u>(273,741)</u>	<u>—</u>
	1,425,022	1,255,386	20,492	(273,741)	2,427,159
Purchased gas cost . . . . .	<u>1,003,977</u>	<u>1,214,395</u>	<u>9,158</u>	<u>(273,042)</u>	<u>1,954,488</u>
Gross profit . . . . .	421,045	40,991	11,334	(699)	472,671
Operating expenses . . . . .	<u>263,004</u>	<u>14,262</u>	<u>5,689</u>	<u>(699)</u>	<u>282,256</u>
Operating income . . . . .	158,041	26,729	5,645	—	190,415
Miscellaneous income (expense) . . . . .	4,001	530	7,771	(4,452)	7,850
Interest charges . . . . .	<u>49,285</u>	<u>2,284</u>	<u>2,389</u>	<u>(4,452)</u>	<u>49,506</u>
Income before income taxes . . . . .	112,757	24,975	11,027	—	148,759
Income tax expense . . . . .	<u>41,636</u>	<u>10,067</u>	<u>4,445</u>	<u>—</u>	<u>56,148</u>
Net income . . . . .	<u>\$ 71,121</u>	<u>\$ 14,908</u>	<u>\$ 6,582</u>	<u>\$ —</u>	<u>\$ 92,611</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

	For the Nine Months Ended June 30, 2003				<u>Consolidated</u>
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Other Nonutility</u> (In thousands)	<u>Eliminations</u>	
Operating revenues from external parties . . . . .	\$1,341,558	\$1,013,426	\$ 8,060	\$ —	\$2,363,044
Intersegment revenues . . . . .	969	325,306	8,182	(334,457)	—
	1,342,527	1,338,732	16,242	(334,457)	2,363,044
Purchased gas cost . . . . .	934,649	1,325,655	1,475	(333,933)	1,927,846
Gross profit . . . . .	407,878	13,077	14,767	(524)	435,198
Operating expenses . . . . .	248,485	7,366	5,313	(524)	260,640
Operating income . . . . .	159,393	5,711	9,454	—	174,558
Miscellaneous income (expense) . . . . .	(872)	1,703	6,067	(3,577)	3,321
Interest charges . . . . .	47,231	2,090	1,935	(3,577)	47,679
Income before income taxes and cumulative effect of accounting change . . . . .	111,290	5,324	13,586	—	130,200
Income tax expense . . . . .	40,796	2,114	5,393	—	48,303
Income before cumulative effect of accounting change	70,494	3,210	8,193	—	81,897
Cumulative effect of accounting change, net of income tax benefit . . . . .	—	(7,773)	—	—	(7,773)
Net income (loss) . . . . .	<u>\$ 70,494</u>	<u>\$ (4,563)</u>	<u>\$ 8,193</u>	<u>\$ —</u>	<u>\$ 74,124</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Balance sheet information at June 30, 2004 and September 30, 2003, by segment, is presented in the following tables:

	<b>At June 30, 2004</b>				
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	<b>(In thousands)</b>				
<b>ASSETS</b>					
Property, plant and equipment, net . . . .	\$1,631,190	\$ 7,981	\$ 45,575	\$ —	\$1,684,746
Investment in subsidiaries . . . . .	156,428	(1,413)	—	(155,015)	—
Current assets					
Cash and cash equivalents . . . . .	108,758	17,263	874	—	126,895
Assets from risk management activities . . . . .	789	13,136	—	(4,372)	9,553
Other current assets . . . . .	164,163	187,366	33,623	(42,135)	343,017
Intercompany receivables . . . . .	—	—	<u>12,781</u>	<u>(12,781)</u>	—
Total current assets . . . . .	<u>273,710</u>	<u>217,765</u>	<u>47,278</u>	<u>(59,288)</u>	<u>479,465</u>
Intangible assets . . . . .	—	4,377	—	—	4,377
Goodwill . . . . .	237,635	21,704	12,128	—	271,467
Noncurrent assets from risk management activities . . . . .					
Deferred charges and other assets . . . . .	—	905	—	(173)	732
	<u>214,724</u>	<u>1,777</u>	<u>23,244</u>	<u>—</u>	<u>239,745</u>
	<u>\$2,513,687</u>	<u>\$253,096</u>	<u>\$128,225</u>	<u>\$(214,476)</u>	<u>\$2,680,532</u>
<b>CAPITALIZATION AND LIABILITIES</b>					
Shareholders' equity . . . . .	\$ 926,846	\$ 90,666	\$ 65,762	\$(156,428)	\$ 926,846
Long-term debt . . . . .	<u>854,803</u>	—	<u>8,463</u>	—	<u>863,266</u>
Total capitalization . . . . .	1,781,649	90,666	74,225	(156,428)	1,790,112
Current liabilities					
Current maturities of long-term debt	3,917	—	2,001	—	5,918
Short-term debt . . . . .	—	—	—	—	—
Liabilities from risk management activities . . . . .	8,227	12,370	—	(4,967)	15,630
Other current liabilities . . . . .	256,430	146,552	32,732	(39,462)	396,252
Intercompany payables . . . . .	<u>4,081</u>	<u>8,700</u>	—	<u>(12,781)</u>	—
Total current liabilities . . . . .	<u>272,655</u>	<u>167,622</u>	<u>34,733</u>	<u>(57,210)</u>	<u>417,800</u>
Deferred income taxes . . . . .	225,632	(8,669)	11,080	(144)	227,899
Noncurrent liabilities from risk management activities . . . . .					
Regulatory cost of removal obligation . .	105,059	—	—	—	105,059
Deferred credits and other liabilities . . .	<u>128,692</u>	<u>1,185</u>	<u>8,187</u>	—	<u>138,064</u>
	<u>\$2,513,687</u>	<u>\$253,096</u>	<u>\$128,225</u>	<u>\$(214,476)</u>	<u>\$2,680,532</u>

**ATMOS ENERGY CORPORATION**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

	At September 30, 2003				
	<u>Utility</u>	<u>Natural Gas Marketing</u>	<u>Other Nonutility</u>	<u>Eliminations</u>	<u>Consolidated</u>
	(In thousands)				
<b>ASSETS</b>					
Property, plant and equipment, net . . . .	\$1,555,381	\$ 9,288	\$ 59,725	\$ —	\$1,624,394
Investment in subsidiaries . . . . .	133,586	(2,662)	—	(130,924)	—
Current assets					
Cash and cash equivalents . . . . .	—	14,880	803	—	15,683
Assets from risk management activities . . . . .	202	22,941	—	(884)	22,259
Other current assets . . . . .	230,609	197,239	85,119	(92,912)	420,055
Intercompany receivables . . . . .	<u>114,550</u>	<u>—</u>	<u>—</u>	<u>(114,550)</u>	<u>—</u>
Total current assets . . . . .	345,361	235,060	85,922	(208,346)	457,997
Intangible assets . . . . .	—	5,030	—	—	5,030
Goodwill . . . . .	233,741	22,600	12,128	—	268,469
Noncurrent assets from risk management activities . . . . .					
	—	1,896	—	(197)	1,699
Investment in US Propane LLC . . . . .	—	—	21,071	—	21,071
Deferred charges and other assets . . . . .	<u>220,258</u>	<u>2,214</u>	<u>25,781</u>	<u>—</u>	<u>248,253</u>
	<u>\$2,488,327</u>	<u>\$273,426</u>	<u>\$204,627</u>	<u>\$(339,467)</u>	<u>\$2,626,913</u>
<b>CAPITALIZATION AND LIABILITIES</b>					
Shareholders' equity . . . . .	\$ 857,517	\$ 74,759	\$ 58,827	\$(133,586)	\$ 857,517
Long-term debt . . . . .	<u>858,720</u>	<u>—</u>	<u>5,198</u>	<u>—</u>	<u>863,918</u>
Total capitalization . . . . .	1,716,237	74,759	64,025	(133,586)	1,721,435
Current liabilities					
Current maturities of long-term debt	8,227	—	1,118	—	9,345
Short-term debt . . . . .	118,595	—	—	—	118,595
Liabilities from risk management activities . . . . .	7,941	13,400	—	(551)	20,790
Other current liabilities . . . . .	190,399	183,082	10,008	(90,470)	293,019
Intercompany payables . . . . .	<u>—</u>	<u>5,549</u>	<u>109,001</u>	<u>(114,550)</u>	<u>—</u>
Total current liabilities . . . . .	325,162	202,031	120,127	(205,571)	441,749
Deferred income taxes . . . . .	221,912	(9,498)	11,081	(145)	223,350
Noncurrent liabilities from risk management activities . . . . .					
	—	928	—	(165)	763
Regulatory cost of removal obligation . .	102,371	—	—	—	102,371
Deferred credits and other liabilities . .	<u>122,645</u>	<u>5,206</u>	<u>9,394</u>	<u>—</u>	<u>137,245</u>
	<u>\$2,488,327</u>	<u>\$273,426</u>	<u>\$204,627</u>	<u>\$(339,467)</u>	<u>\$2,626,913</u>

## ATMOS ENERGY CORPORATION

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

#### 12. Subsequent Event

On July 19, 2004, we completed the public offering of 8,650,000 shares of our common stock. The offering was priced at \$24.75 and generated net proceeds of approximately \$205.6 million before legal, accounting and other offering costs. We also sold an additional 1,289,393 shares of our common stock on July 19, 2004 when our underwriters exercised their overallotment option, which generated net proceeds of approximately \$30.6 million. We intend to use the net proceeds, together with borrowings under the bridge financing facility, for which we have received a commitment, to finance the TXU Gas acquisition described in Note 3. If we do not consummate the TXU Gas acquisition, we intend to use these net proceeds for working capital and other general corporate purposes, including capital spending and purchases of natural gas, which would otherwise have been financed with short-term debt under our commercial paper program.

## 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, 2004, and the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2004 and 2003, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2004 and 2003. 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, 2003, 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 10, 2003, 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, 2003, 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 9, 2004

## **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, 2003.

### ***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, expect, estimate, intends, plans, believes, objective, forecast, goal, 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: successful completion, financing and integration of the Company's pending acquisition of the natural gas distribution and pipeline operations of TXU Gas and other acquisitions the Company has made or may make in the future; 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; changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from other energy suppliers and alternative forms of energy; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the Company. A discussion of these risks and uncertainties may be found in the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and in this Report. 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 other natural gas nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 1.7 million residential, commercial, public-authority and industrial customers through our six 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 supply management and marketing services to municipalities, other local distribution companies and industrial customers located in 18 states. We also construct electric power-generating plants and associated facilities for municipalities and industrial customers to meet their peak-load demands. Beginning April 1, 2004, Atmos Energy Services, LLC, a wholly-owned subsidiary of Atmos Energy Holdings, Inc., began providing natural gas supply management services to our utility operations in a limited number of states. We expect to expand these services to substantially all of our utility service areas before the end of fiscal 2004.

Our operations are divided into three 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 and
- The other nonutility segment, which includes all of our other nonutility operations.

As described in Note 3 to the condensed consolidated financial statements, on June 17, 2004, we entered into a definitive agreement with TXU Gas Company (TXU Gas) to acquire the natural gas distribution and pipeline operations of TXU Gas. The TXU Gas operations we are acquiring 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. TXU Gas provides gas distribution services to over 1.4 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. TXU Gas owns and operates a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas. The purchase price, excluding transaction costs, for the acquisition is \$1.925 billion, which is payable in cash. The price is subject to adjustment if at the time of closing the working capital of TXU Gas is less or more than approximately \$121 million. The price is also subject to increase by the amount of any capital expenditures made by TXU Gas prior to closing that exceed its budgeted amounts. We are not assuming any indebtedness in the transaction.

As described in Notes 3 and 12 to the condensed consolidated financial statements, we expect to finance the acquisition with a combination of debt and common equity. In July 2004, we received \$236.2 million in net proceeds from an offering of common stock. We have a commitment from a financial institution to provide the remaining \$1.7 billion balance of the purchase price under a bridge financing facility that would mature 364 days after the closing date of the acquisition. We expect to pay for any purchase price adjustments and transaction expenses through other short-term debt borrowings. We intend to seek long-term debt and additional common equity financings to refinance the bridge financing facility.

### **Critical Accounting Policies and Estimates**

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. Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. Actual results may differ from 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, 2003 and includes the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Derivatives and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We have designated the

offsetting derivative contracts as cash-flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings when the hedged volumes are sold. This designation is expected to partially reduce the amount of volatility in our condensed consolidated income statement and better reflect the economics of this type of transaction.

There have been no other significant changes to these critical accounting policies during the nine months ended June 30, 2004.

## Results of Operations

The following table presents our financial highlights for the three and nine months ended June 30, 2004 and 2003:

	Three Months Ended June 30		Nine Months Ended June 30	
	2004	2003	2004	2003
	(In thousands, unless otherwise noted)			
Operating revenues	\$546,058	\$488,470	\$2,427,159	\$2,363,044
Gross profit	107,492	95,064	472,671	435,198
Operating expenses	86,032	81,008	282,256	260,640
Operating income	21,460	14,056	190,415	174,558
Miscellaneous income	2,187	686	7,850	3,321
Interest charges	16,011	16,042	49,506	47,679
Income (loss) before income taxes and cumulative effect of accounting change	7,636	(1,300)	148,759	130,200
Income tax expense (benefit)	2,871	(1,099)	56,148	48,303
Cumulative effect of accounting change, net of income tax benefit	—	—	—	(7,773)
Net income (loss)	\$ 4,765	\$ (201)	\$ 92,611	\$ 74,124
Utility sales volumes — MMcf	25,146	25,904	153,011	161,654
Utility transportation volumes — MMcf	17,428	13,903	55,573	49,240
Total utility throughput — MMcf	<u>42,574</u>	<u>39,807</u>	<u>208,584</u>	<u>210,894</u>
Natural gas marketing sales volumes — MMcf	<u>47,640</u>	<u>48,316</u>	<u>173,729</u>	<u>181,013</u>
Heating degree days				
Actual (weighted average)	237	218	3,249	3,437
Percent of normal	94%	86%	96%	101%
Consolidated utility average transportation revenue per Mcf	\$ 0.39	\$ 0.46	\$ 0.42	\$ 0.48
Consolidated utility average cost of gas per Mcf sold	\$ 6.49	\$ 6.23	\$ 6.56	\$ 5.78

The following table shows our operating income by segment for the three-month and nine-month periods ended June 30, 2004 and 2003. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	<b>For the Three Months Ended June 30</b>			
	<b>2004</b>		<b>2003</b>	
	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal</b>	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal</b>
	(In thousands, except degree day information)			
Colorado-Kansas . . . . .	\$ 845	96%	\$ 812	91%
Kentucky . . . . .	3,089	85%	2,788	94%
Louisiana . . . . .	5,625	115%	6,636	87%
Mid-States . . . . .	1,367	83%	955	84%
Mississippi Valley Gas Company . . . . .	(1,559)	116%	(7,991)	101%
Texas . . . . .	4,291	96%	3,066	67%
Other . . . . .	(466)	—	—	—
Utility segment . . . . .	13,192	94%	6,266	86%
Natural gas marketing segment . . . . .	6,847	—	6,062	—
Other nonutility segment . . . . .	1,421	—	1,728	—
Consolidated operating income . . . . .	<u>\$21,460</u>	94%	<u>\$14,056</u>	86%

	<b>For the Nine Months Ended June 30</b>			
	<b>2004</b>		<b>2003</b>	
	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal</b>	<b>Operating Income</b>	<b>Heating Degree Days Percent of Normal</b>
	(In thousands, except degree day information)			
Colorado-Kansas . . . . .	\$ 20,202	99%	\$ 26,049	101%
Kentucky . . . . .	20,895	98%	20,704	100%
Louisiana . . . . .	35,326	93%	37,378	106%
Mid-States . . . . .	38,751	95%	40,019	100%
Mississippi Valley Gas Company <sup>(1)</sup> . . . . .	23,805	101%	18,254	100%
Texas . . . . .	18,458	91%	18,714	98%
Other . . . . .	604	—	(1,725)	—
Utility segment . . . . .	158,041	96%	159,393	101%
Natural gas marketing segment . . . . .	26,729	—	5,711	—
Other nonutility segment . . . . .	5,645	—	9,454	—
Consolidated operating income . . . . .	<u>\$190,415</u>	96%	<u>\$174,558</u>	101%

<sup>(1)</sup> Operating income for Mississippi Valley Gas Company reflects operating income since our acquisition of MVG on December 3, 2002.

**Three Months Ended June 30, 2004 Compared with Three Months Ended June 30, 2003**

*Utility Segment*

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 68 percent of our net income having been earned in the second quarter during the three most recently completed fiscal years. 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, 2004, we had, or received regulatory approvals for, WNA in the following service areas for the following periods, which covered approximately 1.1 million, or 64 percent, of our meters in service:

Tennessee .....	November – April
Georgia .....	October – May
Mississippi .....	November – May
Kentucky .....	November – April
Kansas .....	October – May
Amarillo, Texas <sup>(1)</sup> .....	October – May
West Texas <sup>(2)</sup> .....	October – May
Lubbock, Texas <sup>(3)</sup> .....	October – May

<sup>(1)</sup> Effective for the 2003-2004 winter heating season.

<sup>(2)</sup> Effective for the 2004-2005 winter heating season.

<sup>(3)</sup> Effective beginning in April 2004.

### *Operating Income*

Utility gross profit margin increased to \$93.2 million for the three months ended June 30, 2004 from \$84.6 million for the three months ended June 30, 2003. Total throughput for our utility business was 46.1 billion cubic feet (Bcf) during the current-year quarter, compared to 42.9 Bcf in the prior-year quarter. Excluding intercompany throughput, total consolidated throughput for our utility business was 42.6 Bcf, compared with 39.8 Bcf.

The increase in utility gross profit margin reflects higher throughput primarily attributable to weather that was 9 percent colder than the prior-year quarter. Additionally, the increase in gross profit margin reflects the effect of our rate case increases received in fiscal 2004 in Mississippi, Texas and Kansas. This increase was partially offset by the effect of WNA in our WNA service areas, which decreased our gross profit by \$1.0 million compared with the prior-year quarter, due to colder weather. In addition, the increase in utility gross profit margin was offset by a decrease in consumption attributable to the impact of conservation and the continued introduction of more efficient gas appliances in our service areas.

The average cost of gas per Mcf sold increased 4 percent to \$6.49 for the three months ended June 30, 2004 from \$6.23 for the prior-year quarter. However, changes in the cost of gas do not directly affect utility gross profit margin because the fluctuations in gas prices are passed through to customers.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased 2 percent to \$80.0 million

for the three months ended June 30, 2004 from \$78.3 million for the three months ended June 30, 2003. The increase in operating expense was attributable primarily to higher labor, benefit and insurance costs.

As a result of the factors described above, utility operating income increased by \$6.9 million for the three months ended June 30, 2004 from \$6.3 million for the three months ended June 30, 2003.

#### *Miscellaneous Income (Expense)*

Miscellaneous income for the three months ended June 30, 2004 was \$1.7 million, compared with income of \$1.3 million for the three months ended June 30, 2003. The \$0.4 million change was attributable to the absence in 2004 of weather insurance amortization totaling \$0.6 million, which was recognized in the three months ended June 30, 2003, due to the termination of our weather insurance policy in the third quarter of fiscal 2003.

#### *Natural Gas Marketing Segment*

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers the 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 fees for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. 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 or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, 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 gross profit margin for our storage and marketing activities. Our gross profit margin from marketing activities results from the difference between revenue arising from the sale of physical natural gas to our natural gas marketing customers less the cost to purchase natural gas. The gross profit margin for our storage activities results from the optimization of our managed proprietary and third party storage and transportation assets. These activities include unrealized gains and losses from changes in the market value of derivatives and realized gains and losses from the settlement of derivative contracts.

Our total natural gas marketing segment's gross profit margin was \$11.6 million for the three months ended June 30, 2004 compared to gross profit margin of \$7.4 million for the three months ended June 30, 2003. Natural gas marketing sales volumes were 56.2 Bcf during the current-year quarter compared with 62.4 Bcf for the prior-year quarter. Excluding intercompany sales volumes, natural gas marketing sales volumes were 47.6 Bcf during the current-year quarter, compared to 48.3 Bcf in the prior-year quarter. The decrease in consolidated natural gas marketing sales volumes was primarily due to warmer weather in the current-year quarter. Our natural gas marketing gross profit margin for the three months ended June 30, 2004 included an unrealized loss on open contracts of \$0.1 million compared with an unrealized loss on open contracts of \$4.1 million in the prior-year period.

Our storage activities within the natural gas marketing segment contributed \$3.5 million to gross profit margin for the three months ended June 30, 2004 compared to a \$0.7 million loss for the three months ended

June 30, 2003. The \$4.2 million increase in the contribution from our storage activities was primarily attributable to a \$6.8 million greater unrealized gain in the current quarter associated with our storage portfolio partially offset by a \$2.6 million decrease in the realized storage contributions in the current three-month period compared to the prior-year quarter. The greater unrealized gains in the current quarter were primarily attributable to a favorable movement during the quarter in the inside FERC pricing used to value the physical natural gas inventory partially offset with overall lower physical natural gas storage quantities at June 30, 2004 compared to the prior year quarter-end and an unfavorable movement in the forward indices used to value the storage financial instruments in the prior period.

Our marketing activities contributed \$8.1 million to gross profit margin for both of the three months ended June 30, 2004 and 2003. The stability in the gross profit margin for our marketing activities primarily was attributable to our continued efforts to amend contracts with third parties to transfer risk to our customers and to provide higher gross profit margins and improved position management, which directly offset lower overall sales volumes in the current quarter compared to the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$4.8 million for the three months ended June 30, 2004 from \$1.4 million for the three months ended June 30, 2003. The increase in operating expense was attributable primarily to higher employee incentive compensation costs resulting from the improvement in earnings for the current quarter and an increase in temporary and permanent personnel due to systems and process improvements in the marketing segment.

As a result of the improved gross profit margin, our natural gas marketing segment generated operating income of \$6.8 million for the three months ended June 30, 2004 compared to \$6.1 million for the three months ended June 30, 2003.

#### *Other Nonutility Segment*

Our other nonutility segment provides a variety of services. Through Atmos Pipeline and Storage, LLC we provide storage services to our customers for a fee, as well as capture pricing arbitrage through the use of derivatives. Through Atmos Power Systems, Inc., we construct electric peaking power-generating plants and associated facilities in exchange for a fee and provide operating services to municipalities and industrial customers. Through Atmos Energy Services, LLC, we provide natural gas supply management services to our own utility operations.

#### *Operating Income*

Our other nonutility operating income decreased to \$1.4 million for the three months ended June 30, 2004 from \$1.7 million for the three months ended June 30, 2003. Our other nonutility gross profit margin decreased to \$3.1 million for the three months ended June 30, 2004 from \$3.2 million for the three months ended June 30, 2003. The decrease in our other nonutility gross profit margin was attributable primarily to a decrease in demand charges recognized by Atmos Pipeline and Storage for storage services provided during the current quarter compared to the prior-year quarter and slightly lower transported volumes of approximately 0.1 Bcf by Atmos Pipeline and Storage.

#### *Miscellaneous Income*

Miscellaneous income for the three months ended June 30, 2004 was \$1.6 million, compared with \$0.7 million for the three months ended June 30, 2003. The \$0.9 million increase was attributable primarily to the sale of all remaining limited partnership interests in Heritage Propane Partners, LP formerly owned by USP during the current quarter, partially offset with lower equity earnings from our investment in USP resulting from the sale. With these transactions, we no longer have an interest in the propane industry.

## *Nine Months Ended June 30, 2004 Compared with Nine Months Ended June 30, 2003*

### *Utility Segment*

#### *Operating Income*

Utility gross profit margin increased to \$421.0 million for the nine months ended June 30, 2004 from \$407.9 million for the nine months ended June 30, 2003. Total throughput for our utility business was 220.8 Bcf during the current-year period compared to 223.9 Bcf in the prior-year period. Excluding intercompany throughput, consolidated throughput for our utility business was 208.6 Bcf during the current-year period, compared with 210.9 Bcf in the prior-year period.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of Mississippi Valley Gas Company (MVG) for the entire first quarter in the current fiscal year, compared with one month in the first quarter of the prior fiscal year resulting in an increase in utility gross profit margin and total throughput of \$12.8 million and 5.0 Bcf. Utility gross profit margin also increased due to a \$10.3 million period-over-period increase in the effect of WNA in our WNA service areas. These increases were offset partially by the impact of weather that was 5 percent warmer than that of the prior year and 4 percent warmer than normal, resulting in a decrease of approximately \$12.8 million. Warmer than normal weather particularly impacted our service areas in our Mid-States, Louisiana and Texas divisions. The decrease in throughput also reflects a decrease in consumption attributable to the impact of conservation and the continued introduction of more efficient gas appliances in our service areas. Finally, our utility gross profit margin for the nine months ended June 30, 2004 reflects a reduction resulting from a regulatory ruling to refund \$1.9 million to our customers in our Colorado service area.

The average cost of gas per Mcf sold increased 13 percent to \$6.56 for the nine months ended June 30, 2004 from \$5.78 for the prior-year period. However, changes in the cost of gas do not directly affect utility gross profit margin because the fluctuations in gas prices are passed through to customers.

Operating expenses increased 6 percent to \$263.0 million for the nine months ended June 30, 2004 from \$248.5 million for the nine months ended June 30, 2003. Operation and maintenance expense increased, primarily due to the addition of \$6.1 million related to the MVG acquisition in December 2002 and higher labor and benefit costs. Taxes other than income taxes increased \$1.0 million, primarily due to additional franchise, payroll and property taxes associated with the MVG assets acquired in December 2002. Franchise and state gross receipts taxes are paid by our customers as a component of their monthly bills; thus, these amounts are offset in revenues through customer billings and have no effect on net income. Depreciation and amortization expense increased \$4.0 million, which primarily reflects MVG depreciation for the full nine months of 2004 compared with seven months in the prior-year period. These increases were partially offset by a \$2.9 million reduction in our provision for doubtful accounts attributable to more effective accounts receivable collections during fiscal 2004.

As a result of the aforementioned factors, our utility segment operating income for the nine months ended June 30, 2004 decreased to \$158.0 million from \$159.4 million for the nine months ended June 30, 2003.

#### *Miscellaneous Income (Expense)*

Miscellaneous income for the nine months ended June 30, 2004 was \$4.0 million, compared with expense of \$0.9 million for the nine months ended June 30, 2003. The \$4.9 million change was attributable primarily to the absence in 2004 of weather insurance amortization totaling \$5.0 million, which was recognized in the nine months ended June 30, 2003, due to the termination of our weather insurance policy in the third quarter of fiscal 2003.

#### *Interest Charges*

Interest charges increased 4 percent for the nine months ended June 30, 2004 to \$49.3 million from \$47.2 million for the nine months ended June 30, 2003. The increase was attributable primarily to a higher

average outstanding debt balance resulting from the financing obtained to fund the acquisition of MVG in December 2002.

### *Natural Gas Marketing Segment*

#### *Operating Income*

Our total natural gas marketing segment's gross profit margin was \$41.0 million for the nine months ended June 30, 2004 compared to gross profit margin of \$13.1 million for the nine months ended June 30, 2003. Natural gas marketing sales volumes were 207.6 Bcf during the current-year period compared with 228.5 Bcf for the prior-year period. Excluding intercompany sales volumes, natural gas marketing sales volumes were 173.7 Bcf during the current-year period compared with 181.0 Bcf in the prior-year period. The decrease in consolidated natural gas marketing sales volumes was primarily due to overall warmer temperatures during the 2003-2004 heating season compared with the prior-year period. Our natural gas marketing gross profit margin for the nine months ended June 30, 2004 included an unrealized loss on open contracts of \$2.2 million compared with an unrealized gain on open contracts of \$7.2 million in the prior-year period.

The contribution to gross profit from our storage activities was \$4.0 million for the nine months ended June 30, 2004 compared to a loss of \$0.5 million for the nine months ended June 30, 2003. The \$4.5 million increase primarily was attributable to a \$13.4 million increase in the realized storage contribution for the nine months ended June 30, 2004 compared to the prior-year period offset by an \$8.9 million decrease in unrealized income associated with our storage portfolio compared to the prior-year period. The increase in the realized storage contribution for the nine months ended June 30, 2004 primarily was due to our inability during the 2002-2003 heating season to withdraw planned volumes from storage to meet our customer requirements caused by operational, contractual and regulatory limitations relating to our storage facilities, which reduced our realized storage contributions during the nine months ended June 30, 2003. This situation did not recur during the nine months ended June 30, 2004. The decrease in unrealized income in the current period was primarily attributable to a less favorable movement during the nine months ended June 30, 2004 in the forward indices used to value the storage financial instruments than in the prior period combined with overall lower physical natural gas storage quantities at June 30, 2004 compared to the prior-year period.

Our marketing activities contributed \$37.0 million to our gross profit margin for the nine months ended June 30, 2004 compared to \$13.6 million for the nine months ended June 30, 2003. The increase in the marketing contribution primarily was attributable to our continued efforts to amend contracts with third parties to transfer risk to our customers and to provide higher gross profit margins and improved position management during the current year.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to \$14.3 million for the nine months ended June 30, 2004 from \$7.4 million for the nine months ended June 30, 2003. The increase in operating expense was attributable primarily to higher labor and benefit costs resulting from the improvement in earnings for the fiscal year and an increase in temporary and permanent personnel due to systems and process improvements in the marketing segment.

The improved gross profit margin resulted in an increase in our natural gas marketing segment operating income to \$26.7 million for the nine months ended June 30, 2004 compared with operating income of \$5.7 million for the nine months ended June 30, 2003.

#### *Cumulative Effect of Change in Accounting Principle*

On January 1, 2003, we recorded a cumulative effect of a change in accounting principle to reflect a change in the way we account for our storage and transportation contracts. Previously, we accounted for those contracts under EITF 98-10, *Accounting for Energy Trading and Risk Management Activities*, which required us to record estimated future gains on our storage and transportation contracts at the time we entered into the contracts and to mark those contracts to market value each month. Effective January 1, 2003, we have no longer marked those contracts to market. As a result, our natural gas marketing segment recognized an

extraordinary charge of \$7.8 million, net of applicable income tax benefit, as a cumulative effect of a change in accounting principle.

*Other Nonutility Segment*

***Operating Income***

Our other nonutility operating income decreased to \$5.6 million for the nine months ended June 30, 2004 from \$9.5 million for the nine months ended June 30, 2003. The decrease in our other nonutility gross profit margin was attributable primarily to a decrease in demand charges recognized by Atmos Pipeline and Storage for storage services provided during the nine months ended June 30, 2004 compared to the prior-year period and lower transported volumes of approximately 2.3 Bcf by Atmos Pipeline and Storage due to overall warmer weather during the winter heating season.

***Miscellaneous Income***

Miscellaneous income for the nine months ended June 30, 2004 was \$7.8 million, compared with income of \$6.1 million for the nine months ended June 30, 2003. The \$1.7 million increase was attributable primarily to a \$5.9 million pretax gain associated with the sale of our general and limited partnership interests in USP and the sale of the remaining limited partnership units in Heritage Propane Partners, L.P. formerly owned by USP in January and June 2004. This increase was offset partially by lower equity earnings from our investment in USP resulting from the sale and the absence in 2004 of a \$3.9 million gain recorded in 2003 associated with a sales-type lease of a distributed electric generation plant.

**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 fiscal 2004. Our cash needs for working capital and capital expenditures will increase as a result of the acquisition of the natural gas distribution and pipeline operations of TXU Gas, which we expect to close in the first quarter of fiscal 2005. We believe that these needs can be provided from the same sources of capital.

***Capitalization***

The following presents our capitalization as of June 30, 2004 and September 30, 2003:

	<u>June 30, 2004</u>		<u>September 30, 2003</u>	
	(In thousands, except percentages)			
Short-term debt . . . . .	\$ —	—	\$ 118,595	6.4%
Long-term debt . . . . .	869,184	48.4%	873,263	47.2%
Shareholders' equity . . . . .	<u>926,846</u>	<u>51.6%</u>	<u>857,517</u>	<u>46.4%</u>
Total capitalization, including short-term debt . . .	<u>\$1,796,030</u>	<u>100.0%</u>	<u>\$1,849,375</u>	<u>100.0%</u>

Total debt as a percentage of total capitalization, including short-term debt, was 48.4 percent at June 30, 2004 compared with 53.6 percent at September 30, 2003. As a result of our pending acquisition of the natural gas distribution and pipeline operations of TXU Gas, we expect our debt-to-capitalization ratio to increase to a range of 67 to 70 percent when we incur indebtedness under our bridge financing facility. This ratio could be greater depending on our working capital requirements during the upcoming winter heating season as we may make additional short-term borrowings to fund natural gas purchases. After refinancing our bridge financing facility, in part with additional issuances of common stock, we expect our debt to capital ratio to range from 58 to 62 percent. Within three to five years from the closing of the acquisition, we intend to reduce our capitalization ratio to a target range of 53 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 limits to annual maintenance and capital expenditures. We are currently assessing our working capital requirements as a result of the pending acquisition of the TXU Gas operations and we expect these requirements will significantly increase after the closing of the acquisition.

### *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 and other factors. These also include the successful integration of the natural gas distribution and pipeline operations of TXU Gas we are acquiring.

### *Cash Flows from Operating Activities*

Year-over-year changes in our operating cash flows are attributable primarily to 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, 2004, we generated operating cash flow of \$359.3 million compared with \$117.3 million for the nine months ended June 30, 2003. Our cash flow from operating activities was affected by the following:

- Improved customer collections during the nine months ended June 30, 2004, compared with the prior-year period, resulted in a \$64.8 million increase in operating cash flows.
- Seasonal reductions in our natural gas inventories resulted in a \$54.6 million increase 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 improved cash flows from operations by \$28.0 million.
- Alternatively, the timing of payments for accounts payable and other accrued liabilities adversely affected operating cash flow by \$23.6 million.
- Other working capital changes improved operating cash flow by \$118.2 million. These working capital changes primarily related to increases in pension and post-retirement liabilities, income taxes payable and other current liabilities.

### *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 and technology improvements. Capital expenditures for fiscal 2004 are expected to approximate \$175.0 million. These expenditures will include additional mains, services, meters and equipment. We are currently assessing our capital expenditure requirements as a result of the pending acquisition of the TXU Gas operations, and we believe these requirements will significantly increase after the closing of the acquisition.

For the nine months ended June 30, 2004, we invested \$104.1 million compared with \$188.0 million for the nine months ended June 30, 2003. Cash flows used for investing activities for the current year include the receipt of proceeds totaling \$27.9 million from the sale of our limited and general partnership interests in USP in January 2004 (\$24.7 million), the sale of the remaining limited partnership units in Heritage Propane Partners, L.P. formerly owned by USP (\$1.9 million) and the sale of a building (\$1.3 million). Cash flows used for investing activities for the current year included \$2.0 million for the ComFurT Gas Inc. acquisition and \$74.7 million in the prior-year period for the cash portion of the Mississippi Valley Gas Company purchase in December 2002. Capital expenditures were \$129.5 million during the nine months ended June 30, 2004 compared with \$113.6 million for the prior-year period. Capital projects for each nine-month period included expenditures for additional mains, services, meters and equipment to grow our customer base. Additionally, capital expenditures for the current-year period include approximately \$12.3 million for

Mississippi Valley Gas Company Division capital expenditures, compared with \$8.6 million in the prior-year period.

*Cash Flows from Financing Activities*

For the nine months ended June 30, 2004 our financing activities used \$144.0 million of cash compared with \$41.2 million cash provided for the nine months ended June 30, 2003. Our significant financing activities for the nine months ended June 30, 2004 and 2003 are summarized as follows:

- During the nine months ended June 30, 2003, we received \$147.0 million from a short-term acquisition credit facility which was used primarily to fund the \$74.7 million cash portion of the purchase price for MVG in December 2002 and to repay \$70.9 million of MVG's outstanding debt. This facility was subsequently repaid with a portion of the net proceeds received from our \$250.0 million debt offering completed in January 2003.
- Total short-term debt decreased by \$118.6 million and \$145.1 million for the nine months ended June 30, 2004 and 2003 reflecting the repayment of our lines of credit used to fund our natural gas purchases for the winter heating season.
- We repaid \$9.1 million of long-term debt during the nine months ended June 30, 2004 compared with a repayment of \$72.3 million for the nine months ended June 30, 2003, reflecting the payment of scheduled maturities on our long-term debt instruments and the \$54.0 million repayment of unsecured senior notes in the second quarter of fiscal 2003 with the proceeds received from our January 2003 debt offering.
- We received \$5.0 million in long-term debt for our other nonutility segment to refinance intercompany debt with third-party debt during the second quarter of 2004.
- We paid \$47.6 million in cash dividends during the nine months ended June 30, 2004 compared with dividend payments of \$39.9 million for the prior-year period. The increase in dividends paid reflects the 1.7 percent increase in the quarterly dividend rate approved by the Board of Directors and the increase in the number of shares outstanding as a result of the shares issued in connection with our public offering in June and July 2003 (the 2003 Offering), the funding of our pension plan in June 2003 and the acquisition of MVG in December 2002.

During the nine months ended June 30, 2004, we issued 1,103,518 shares of common stock, generating proceeds of \$26.3 million. The following table summarizes the issuances for the nine months ended June 30, 2004 and 2003:

	<b>Nine Months Ended June 30</b>	
	<b>2004</b>	<b>2003</b>
Shares issued:		
Direct Stock Purchase Plan .....	426,960	419,223
Long-Term Incentive Plan .....	426,943	164,532
Retirement Savings Plan .....	241,257	275,222
Long-Term Stock Plan for Mid-States Division .....	6,000	13,000
Outside Directors Stock-for-Fee Plan .....	2,358	2,178
Pension account plan funding .....	—	1,169,700
Acquisition of Mississippi Valley Gas Company .....	—	3,386,287
Equity offering .....	—	<u>4,000,000</u>
Total shares issued .....	<u>1,103,518</u>	<u>9,430,142</u>

### *Shelf Registration*

In December 2001, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to \$600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC on January 30, 2002. On January 16, 2003, we issued \$250.0 million of 5<sup>1</sup>/<sub>8</sub> percent Senior Notes due in 2013 under the registration statement. The net proceeds of \$249.3 million were used to repay debt under an acquisition credit facility used to finance our acquisition of MVG, to repay \$54.0 million in unsecured senior notes held by institutional lenders and short-term debt under our commercial paper program and to provide funds for general corporate purposes. Additionally, we sold 4,100,000 shares of our common stock in connection with our 2003 Offering under the registration statement to provide additional funding for our Pension Account Plan.

At June 30, 2004, approximately \$246.0 million remained available, subject to certain regulatory approvals, under the shelf registration statement. However, in July 2004 we sold 9,939,393 shares of our common stock, including the underwriters' exercise of their overallotment option. We intend to use the net proceeds from this offering, together with borrowings under the bridge financing facility to consummate the acquisition of the natural gas distribution and pipeline operations of TXU Gas. In the event we do not consummate the acquisition, we intend to use the net proceeds from the offering for working capital and general corporate purposes. As a result of the offering, we currently have no availability remaining under the shelf registration statement. However, we intend to file another shelf registration statement, subject to regulatory approval, and seek to issue additional common equity and long-term debt to refinance the bridge financing facility within 364 days from the closing of the acquisition.

### *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. These facilities are described in further detail in Note 6 to the condensed consolidated financial statements. Where necessary, we and our lead bank plan to amend these facilities' terms prior to closing the TXU Gas acquisition to accommodate the expected increase in our debt to capital ratio that will result from the acquisition.

### *Credit Rating*

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 risk 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 as follows:

	<u>S&amp;P</u>	<u>Moody's</u>	<u>Fitch</u>
Long-term debt . . . . .	A-	A3	A-
Commercial paper . . . . .	A-2	P-2	F-2

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.

Prior to our announcement on June 17, 2004 of our intent to acquire the natural gas distribution and pipeline operations of TXU Gas, Moody's and Fitch each maintained a "stable" outlook for our ratings, while S&P maintained a "negative" outlook. Subsequent to this announcement, all three agencies placed our long-term debt ratings on credit watch for a potential downgrade. S&P and Moody's also placed our commercial paper ratings on credit watch. We have conducted discussions with all three rating agencies and have provided substantial amounts of information to them in order to facilitate their review of our ratings. Based on these discussions, we expect that all three agencies will complete their ratings review at or prior to the closing of the TXU Gas acquisition and will maintain investment grade ratings for our long-term debt.

On August 6, 2004, Moody's announced that it expects our ratings will remain investment grade, with our long-term debt rating likely to fall to Baa3 when it complete its ratings review. In that event, Moody's is likely to lower our P-2 commercial paper rating. If our commercial paper rating is lowered, it may reduce or eliminate our ability to access the commercial paper markets. If we are unable to issue commercial paper, we will borrow under our \$350.0 million and \$18.0 million bank credit facilities to meet our working capital needs. This would increase the cost of our working capital financing. This would also increase the cost of the financing for the acquisition of the TXU Gas operations under the bridge financing facility.

### ***Debt Covenants***

In addition to the limit on our total debt-to-capitalization ratio imposed by our committed credit facilities described above, 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, 1988, may not exceed the sum of accumulated net income for periods after December 31, 1988, plus \$15.0 million. At June 30, 2004, approximately \$129.1 million of retained earnings was unrestricted with respect to the payment of dividends.

We are in compliance with all of our debt covenants as of June 30, 2004. 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 \$350.0 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 \$15 million to \$25 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 any other financial obligation, as defined, by at least \$250 thousand. 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 Baa1.

We have no trigger 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 trigger events.

### ***Contractual Obligations and Commercial Commitments***

Other than changes to our risk management assets and liabilities discussed below, there have been no significant changes in our contractual obligations and commercial commitments during the three- and nine-month periods ended June 30, 2004.

### ***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. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the condensed consolidated financial statements.

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 table shows 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, 2004 and 2003:

	Three Months Ended June 30, 2004		Three Months Ended June 30, 2003	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period . . .	\$ 294	\$1,187	\$ 1,202	\$ 8,262
Contracts realized/settled . . . . .	849	(836)	432	(6,667)
Fair value of new contracts . . . . .	(7,749)	—	246	630
Other changes in value . . . . .	(832)	144	(2,678)	5,049
Fair value of contracts at end of period . . . . .	<u>\$ (7,438)</u>	<u>\$ 495</u>	<u>\$ (798)</u>	<u>\$ 7,274</u>
	Nine Months Ended June 30, 2004		Nine Months Ended June 30, 2003	
	Utility	Natural Gas Marketing	Utility	Natural Gas Marketing
	(In thousands)			
Fair value of contracts at beginning of period . . .	\$ (7,739)	\$10,144	\$ 4,424	\$ 6,651
Contracts realized/settled . . . . .	(3,296)	(6,030)	(2,019)	4,910
Fair value of new contracts . . . . .	(7,427)	(797)	129	5,261
Other changes in value . . . . .	11,024	(2,822)	(3,332)	(749)
Cumulative effect of accounting change . . . . .	—	—	—	(8,799)
Fair value of contracts at end of period . . . . .	<u>\$ (7,438)</u>	<u>\$ 495</u>	<u>\$ (798)</u>	<u>\$ 7,274</u>

The fair value of our utility and natural gas marketing derivative contracts at June 30, 2004, is segregated below by time period and fair value source.

Source of Fair Value	Fair Value of Contracts at June 30, 2004				Total Fair Value
	Maturity in Years				
	Less than 1	1-3	4-5	Greater than 5	
	(In thousands)				
Prices actively quoted . . . . .	\$ 6,477	\$ (107)	\$—	\$—	\$ 6,370
Prices provided by other external sources . . . . .	(12,441)	(180)	—	—	(12,621)
Prices based on models and other valuation methods . . . . .	(113)	(579)	—	—	(692)
Total Fair Value . . . . .	<u>\$ (6,077)</u>	<u>\$ (866)</u>	<u>\$—</u>	<u>\$—</u>	<u>\$ (6,943)</u>

A significant portion of AEM's stored gas inventory as of June 30, 2004 was scheduled to be sold within six months. Since AEM actively manages and optimizes its portfolio, it may change its scheduled injection and withdrawal plans based on market conditions. Therefore, we cannot predict that our actual inventory withdrawals will match the planned schedule as of June 30, 2004. Generally, differences between injection and withdrawal prices are locked-in through the use of derivatives; therefore, there is generally no significant

permanent earnings impact associated with changes in monthly prices in the interim between injections and withdrawals. However, there may be significant earnings volatility. Further, permanent earnings impacts may arise if we experience operational or other issues which limit our ability to optimally manage our stored gas positions. Any change in the timing of planned injections or withdrawals from one time period to another generally is conducted to enhance the future profitability of the storage position. Additionally, AEM monitors and adjusts the amount of storage capacity it holds on a discretionary basis.

### ***Pension and Postretirement Benefits Obligations***

For the nine months ended June 30, 2004 and 2003 our total net periodic pension and other benefits cost was \$19.9 million and \$21.0 million. A portion of these costs is capitalized into our utility rate base, as these costs are recoverable through our gas utility rates. Costs that are not capitalized are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during the nine months ended June 30, 2004 compared with the nine months ended June 30, 2003 primarily reflects the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), beginning with the second quarter of fiscal 2004, which reduced our accumulated postretirement benefit obligation and our net postretirement benefit obligation costs by \$4.1 million. The total income statement impact will approximate \$2.3 million, as a portion of this benefit will be capitalized.

This decrease was partially offset by an increase in the service cost and interest cost attributable to an increase in the projected benefit obligation. The increase in the projected benefit obligation resulted primarily from an increase in the number of plan participants due to the MVG acquisition. Additionally, the expected return on plan assets, which reduces the net periodic pension cost and other benefits cost, increased as compared with the prior year primarily due to the effects of the contributions we made to the Atmos Pension Account Plan in fiscal 2003.

In our Annual Report on Form 10-K for the year ended September 30, 2003, we disclosed that anticipated additional voluntary contributions ranging from \$0 to \$15 million during fiscal 2004 may be necessary to keep the Atmos Energy Corporation Pension Account Plan (the Pension Account Plan) 100 percent funded on an accumulated benefit obligation (ABO) basis. We did not contribute to our pension plan during the nine months ended June 30, 2004 and we do not anticipate voluntarily contributing to the Pension Account Plan during the remainder of fiscal 2004.

### **Risks Relating to the Acquisition of the TXU Gas Operations**

In addition to the factors affecting our company and our industry described or referenced elsewhere in this Report, the risks outlined below relating to the acquisition of the TXU Gas operations could also adversely affect our business, financial condition or results of operations.

#### ***Our completion of the acquisition depends upon the receipt of financing under the proposed bridge financing facility whose terms and conditions are not fully negotiated.***

We have received a commitment from a financial institution to provide the financing required for the acquisition through the bridge financing facility. Although we believe the terms of the commitment are suitable for our financing requirements in connection with the acquisition, we still must negotiate the final terms and the definitive documentation for the bridge financing facility. The pricing anticipated for the bridge financing facility would increase if the bridge financing facility cannot be syndicated on the terms contemplated by the commitment letter. Additionally, other terms and conditions of the bridge financing facility may not be as currently anticipated. Our obligations under the agreement for the acquisition are not conditioned upon our entering into the bridge financing facility on particular terms or completing the financing under the bridge financing facility. If we fail to enter into the bridge financing facility or it does not close, we would be required to seek alternative sources of financing for the acquisition. For regulatory and other reasons, we may not be successful in obtaining alternative financing on reasonable terms, if at all. If we could not obtain

alternative sources of financing, we would be unable to complete the acquisition and would breach our obligations under the acquisition agreement.

***We may not be able to refinance the bridge financing facility when required or on reasonable terms.***

The bridge financing facility will be limited to a term of 364 days from the closing of the acquisition. As a result, we will be required to find long-term financing to refinance the bridge financing facility prior to its maturity. We intend to refinance the bridge financing facility with the proceeds we receive from long-term debt and additional common equity financings. The issuance of additional debt and common stock will require regulatory approvals in several of the states in which we operate and the filing of one or more registration statements with the SEC. There can be no assurance that we will obtain the necessary regulatory approvals to issue additional securities or that we will be able to issue long-term debt or common stock on reasonable terms, if at all. If we fail to refinance the bridge financing facility when it becomes due, it would be an event of default under the terms of the bridge financing facility that could result in the acceleration of the repayment of our other indebtedness and force us, at significant expense, to refinance all or a portion of our indebtedness or sell a portion of our business to repay our indebtedness.

In addition, holders of about 2.4 million shares of our common stock have registration rights that require us to register their shares for sale or that may allow them to participate in equity offerings under future registration statements. This may restrict our ability to raise capital through the issuance of common stock. Moreover, depending on future market conditions, sales of additional common stock would be dilutive to our shareholders.

***Our indebtedness and leverage will increase materially with the TXU Gas acquisition.***

The significant increase in our indebtedness and leverage in connection with the acquisition, as described in this Report, could limit our flexibility in planning for, or reacting to, changes in our business or economic conditions. This increase may also result in a decline in our credit ratings. A decline in our ratings would increase our cost of capital and could limit our access to the credit markets. It could also increase the cost or reduce the extent of our commodity hedging activities. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and the anticipated costs of our bridge financing facility. In addition, the borrowing capacity of our gas marketing affiliate could be reduced if our credit ratings are lowered.

***We may not be able to implement the TXU Gas acquisition successfully.***

The acquisition of the TXU Gas operations is larger than any of the nine other acquisitions we have made since 1986. In addition to operating the TXU Gas distribution system as our largest division, we will manage pipeline operations on a scale greater than in the past. As a consequence, we may experience the need for additional management attention and resources or unanticipated challenges or delays in integrating the TXU Gas operations into our business. In addition, employees important to the TXU Gas operations we are acquiring may decide not to continue employment with us. If these events occur, the acquired operations may not achieve the results or otherwise perform as expected.

***The TXU Gas operations are subject to their own risks, which we may not be able to manage successfully.***

The financial results of the TXU Gas operations we are acquiring are subject to many of the same factors that affect our financial condition and results of operations, including weather sensitivity, extensive federal, state and local regulation, increasing gas costs, competition, market risks and national, regional and local economic conditions.

In addition, the TXU Gas distribution operations we are acquiring do not have weather normalized rates. This means we would not be able to increase customers' bills to offset lower gas usage when the weather is warmer than normal. As a result, the financial results for the TXU Gas operations we are acquiring may be

adversely affected in the event of a warmer than normal heating season unless we are able to obtain weather normalization adjustments from the Texas regulatory authorities.

The TXU Gas transmission operations we are acquiring include interconnected natural gas transmission lines, underground storage reservoirs, compressor stations and related properties within Texas. The operation of these transmission facilities also involves risks. These include the possibility of breakdown or failure of equipment or pipelines, the impact of unusual or adverse weather conditions or other natural events and the risk of performance below expected levels of throughput or efficiency. Breakdown or reduced performance of a transmission facility may prevent the facility from performing under applicable sales agreements which, in certain situations, could result in termination of those agreements or incurring a liability for liquidated damages. Insurance, warranties, indemnities or performance guarantees may not cover any or all of the liquidated damages, lost revenues or increased expenses associated with a breakdown or reduction in performance of a transmission facility. If we are unsuccessful in managing these risks, our business, financial condition and results of operations could be adversely affected.

***We have only limited recourse under the acquisition agreement for losses relating to the TXU Gas acquisition.***

The diligence conducted in connection with the TXU Gas operations and the indemnification provided in the acquisition agreement may not be sufficient to protect us from, or compensate us for, all losses resulting from the acquisition or TXU Gas's prior operations. For example, under the terms of the acquisition agreement, the first \$15 million of many indemnifiable losses are to be borne by us, and the agreement provides for sharing of losses with respect to unknown environmental matters that may affect the assets we are acquiring after we have borne \$10 million in costs relating to such matters. In addition, under the terms of the acquisition agreement, the maximum aggregate amount of such losses for which TXU Gas will indemnify us is approximately \$192.5 million. A material loss associated with the TXU Gas acquisition for which there is not adequate indemnification could negatively affect our results of operations, our financial condition and our reputation in the industry and reduce the anticipated benefits of the acquisition.

***There may be other risks or costs resulting from the TXU Gas acquisition that are not known to us.***

We may not be aware of all of the risks associated with the acquisition of the TXU Gas operations. Any discovery of adverse information concerning the assets that we are acquiring after the closing of the acquisition could be material and, in many cases, would be subject to only limited rights of recovery. In addition, following completion of the acquisition, we will likely have to make capital expenditures, which may be significant, but which amount has not been fixed, to enhance or integrate the assets and operations we acquire.

## Operating Statistics and Other Information

The following tables present certain operating statistics for our utility, natural gas marketing and other nonutility segments for the three months and nine months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified to conform to the current-year presentation.

### Utility Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2004	2003	2004	2003 <sup>(1)</sup>
<b>METERS IN SERVICE, end of period</b>				
Residential . . . . .	1,506,643	1,499,780	1,506,643	1,499,780
Commercial . . . . .	152,025	151,601	152,025	151,601
Industrial . . . . .	2,460	2,844	2,460	2,844
Agricultural . . . . .	8,706	9,796	8,706	9,796
Public authority and other . . . . .	10,174	9,955	10,174	9,955
Total meters . . . . .	<u>1,680,008</u>	<u>1,673,976</u>	<u>1,680,008</u>	<u>1,673,976</u>
<b>HEATING DEGREE DAYS<sup>(2)</sup></b>				
Actual (weighted average) . . . . .	237	218	3,249	3,437
Percent of normal . . . . .	94%	86%	96%	101%
<b>UTILITY SALES VOLUMES — MMcf<sup>(3)</sup></b>				
Gas sales volumes				
Residential . . . . .	10,842	10,543	85,223	90,444
Commercial . . . . .	6,384	6,057	38,852	40,142
Industrial . . . . .	4,954	5,283	17,746	19,016
Agricultural . . . . .	1,616	2,845	2,421	3,656
Public authority and other . . . . .	1,350	1,176	8,769	8,396
Total gas sales volumes . . . . .	25,146	25,904	153,011	161,654
Utility transportation volumes . . . . .	20,957	17,014	67,749	62,244
Total utility throughput . . . . .	<u>46,103</u>	<u>42,918</u>	<u>220,760</u>	<u>223,898</u>
<b>UTILITY OPERATING REVENUES (000's)<sup>(3)</sup></b>				
Gas sales revenues				
Residential . . . . .	\$ 128,886	\$ 118,061	\$ 830,154	\$ 782,382
Commercial . . . . .	60,849	55,180	348,820	320,716
Industrial . . . . .	32,483	35,968	122,835	120,497
Agricultural . . . . .	11,299	18,162	16,430	23,455
Public authority and other . . . . .	11,607	8,269	68,553	59,327
Total utility gas sales revenues . . . . .	245,124	235,640	1,386,792	1,306,377
Transportation revenues . . . . .	6,987	7,254	24,058	27,102
Other gas revenues . . . . .	4,141	3,104	14,172	9,048
Total utility operating revenues . . . . .	<u>\$ 256,252</u>	<u>\$ 245,998</u>	<u>\$1,425,022</u>	<u>\$1,342,527</u>
Utility average transportation revenue per Mcf . . . . .	\$ 0.33	\$ 0.43	\$ 0.36	\$ 0.44
Utility average cost of gas per Mcf sold . . . . .	\$ 6.49	\$ 6.23	\$ 6.56	\$ 5.78

See footnotes following these tables.

*Natural Gas Marketing and Other Nonutility Operations Sales and Statistical Data*

	Three Months Ended June 30		Nine Months Ended June 30	
	2004	2003	2004	2003
<b>CUSTOMERS, end of period</b>				
Industrial .....	760	589	760	589
Municipal .....	95	140	95	140
Total .....	<u>855</u>	<u>729</u>	<u>855</u>	<u>729</u>
<b>NATURAL GAS MARKETING SALES</b>				
<b>VOLUMES — MMcf<sup>(3)</sup></b> .....	56,226	62,416	207,582	228,527
<b>OPERATING REVENUES (000's)<sup>(3)</sup></b>				
Natural gas marketing .....	\$364,339	\$374,832	\$1,255,386	\$1,338,732
Other nonutility .....	6,210	3,685	20,492	16,242
Total operating revenues .....	<u>\$370,549</u>	<u>\$378,517</u>	<u>\$1,275,878</u>	<u>\$1,354,974</u>

Notes to preceding tables:

- (1) The operational and statistical information includes the operations of MVG since the December 3, 2002 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 months ended June 30, 2004 and 2003 is adjusted for service areas that have weather normalized operations.
- (3) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

### ***Recent Ratemaking Activity***

The following will discuss our recent ratemaking activities during fiscal 2004. 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.

*Kansas.* In May 2003, we filed a rate case with the Kansas Corporation Commission for approximately \$7.4 million in additional annual revenues. In January 2004, the Kansas Corporation Commission approved an agreement that allowed a \$2.5 million increase in our rates effective March 1, 2004. Additionally, the agreement allows us to increase our monthly customer charges from \$5 to \$8 and provides that we will not file another full rate application prior to September 1, 2005. WNA became effective in Kansas in October 2003 in accordance with the Kansas Corporation Commission's ruling in May 2003.

*Colorado.* In April 2004, we agreed to credit Colorado customers a total of \$1.9 million pending approval of the agreement by the Colorado Public Utility Commission. The agreement was a result of an inquiry by the Colorado Office of Consumer Counsel related to our earnings in Colorado. The staff of the Colorado Public Utility Commission is also a party to the agreement. We accrued this reduction during the three months ended March 31, 2004.

*Virginia.* In February 2004, we filed a rate case with the Virginia Corporation Commission to request a \$1.0 million increase in our base rates, WNA and recovery of the gas cost component of bad debt expense. The Virginia Corporation Commission is currently reviewing our filings and a hearing to review the case has been scheduled for October 2004.

*Texas.* In September 2003, we filed a rate case in our West Texas System to request a \$7.7 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. In May 2004, the 66 cities in our West Texas System approved an increase of \$3.2 million in our annual utility revenues. The cities also approved a WNA Rider for residential, commercial, public-authority and state-institution customers. This Rider will become effective in October 2004.

In October 2003, we filed a rate case in Lubbock to request a \$3.0 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. The City of Lubbock has approved a \$1.5 million increase effective March 1, 2004, as well as the proposed WNA.

Beginning in October 2003, WNA became effective for our Amarillo service area in accordance with an agreement approved by the City of Amarillo in August 2003.

*Mississippi.* The Mississippi Public Service Commission requires that we file for rate adjustments every six months. The rate filings are made in May and November of each year and the rate adjustments typically become effective in June and December. In October 2003, the Mississippi Public Service Commission issued a final order that denied our May 2003 request for a rate adjustment. However, we filed our second semiannual filing on November 5, 2003, and received an annual rate increase of \$5.9 million effective on December 1, 2003. We filed our first semiannual filing for 2004 on May 5, 2004 and we received a preliminary annual rate increase of \$5.7 million effective on June 1, 2004. However, the final ruling is subject to the resolution of certain issues raised by the Mississippi Public Service Commission.

### **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.

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 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 2004, a hypothetical 10 percent increase in fixed prices based upon the June 30, 2004 three month market strip would have increased our purchased gas cost by approximately \$3.7 million in fiscal 2004.

### *Natural Gas Marketing Segment*

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) at the end of each period. Based on AEH's net open position (including existing storage) at June 30, 2004 of 0.4 Bcf, a \$0.50 change in the forward NYMEX price would have had less than a \$0.2 million impact on our consolidated net income.

## **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 \$1.7 million.

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 \$66.1 million.

As of June 30, 2004 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(e) and 15d-15(e). 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 controls and procedures designed to ensure that all information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods set forth in applicable Securities and Exchange Commission forms, rules and regulations.

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 2004 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***

See Note 9 to the condensed consolidated financial statements for a description of our legal proceedings.

### **Item 6. *Exhibits and Reports on Form 8-K***

#### *(a) 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.

#### *(b) Reports on Form 8-K*

The Company filed a Form 8-K Current Report, Item 5, Other Events, dated June 17, 2004, announcing that the Company had issued a news release that it had entered into a definitive agreement to acquire through a merger substantially all of the operations of TXU Gas Company, a wholly-owned subsidiary of TXU Corp., for \$1.925 billion in cash. The purchase price includes approximately \$121 million in working capital and will not include the assumption by Atmos Energy of any of the outstanding debt of TXU Gas. The closing of the acquisition, which Atmos Energy expects to occur by December 31, 2004, is subject to the satisfaction of customary conditions and applicable regulatory approvals. Atmos Energy expects to initially fund the acquisition through the issuance of commercial paper, with the issuance to be supported by a fully underwritten committed 364-day bank credit facility. Under Item 7, Financial Statements and Exhibits, an exhibit was attached: a News Release dated June 17, 2004.



**EXHIBITS INDEX**  
**Item 6(a)**

<u>Exhibit Number</u>	<u>Description</u>	<u>Page Number</u>
10.1	Revolving Credit Agreement, dated as of July 23, 2004 among Atmos Energy Corporation, Bank One NA, Suntrust Bank, Bank of America N.A. and the lenders identified therein	
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 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.