FR 16(12)(p)

## REQUEST:

(12) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(p) A copy of the utility's annual report on Form 10-K as filed with the Securities and Exchange Commission for the most recent two (2) years, and any Form 8-K issued during the past two (2) years, and any Form 10-Q issued during the past six (6) quarters;

## RESPONSE:

Please see attachment FR_16(12)(p)_Att1 for the Form 10-Q filings during the last six quarters, attachment FR_16(12)(p)_Att2 for the Form 10-K filings during the last two years, attachment FR_16(12)(p)_Att3 for the Form 8-K filings during the last two years, attachment FR_16(12)(p)_Att4 for the Statistical Summaries during the last two years, and attachment FR_16(12)(p)_Att 5 for the Summary Annual Reports during the last two years.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, FR_16(12)(p)_Att1 - Form 10-Q.pdf, 324 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, FR_16(12)(p)_Att2 - Form 10-K.pdf, 275 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, FR_16(12)(p)_Att3 - Form 8-K.pdf, 946 Pages.

ATTACHMENT 4 - Atmos Energy Corporation, FR_16(12)(p)_Att4 - Statistical Summaries.pdf, 60 Pages.

ATTACHMENT 5 - Atmos Energy Corporation, FR_16(12)(p)_Att5 - Summary Annual Reports.pdf, 66 Pages.

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

# Form 10-Q

(Mark One)

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

**For the quarterly period ended December 31, 2012**

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of February 1, 2013.

| Class | Shares Outstanding |
|---|---|
| No Par Value | 90,517,509 |

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AOCI | Accumulated other comprehensive income |
| APS | Atmos Pipeline and Storage, LLC |
| Bcf | Billion cubic feet |
| CFTC | Commodity Futures Trading Commission |
| FASB | Financial Accounting Standards Board |
| Fitch | Fitch Ratings, Ltd. |
| GAAP | Generally Accepted Accounting Principles |
| GRIP | Gas Reliability Infrastructure Program |
| GSRS | Gas System Reliability Surcharge |
| ISRS | Infrastructure System Replacement Surcharge |
| LPSC | Louisiana Public Service Commission |
| Mcf | Thousand cubic feet |
| MMcf | Million cubic feet |
| MPSC | Mississippi Public Service Commission |
| Moody's | Moody's Investors Services, Inc. |
| NYMEX | New York Mercantile Exchange, Inc. |
| PPA | Pension Protection Act of 2006 |
| PRP | Pipeline Replacement Program |
| RRC | Railroad Commission of Texas |
| RRM | Rate Review Mechanism |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| WNA | Weather Normalization Adjustment |

## PART I. FINANCIAL INFORMATION

**Item 1.** *Financial Statements*

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED BALANCE SHEETS

| | December 31, 2012 | September 30, 2012 |
|---|---|---|
| | (Unaudited) | |
| | (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $7,283,533 | $7,134,470 |
| Less accumulated depreciation and amortization | 1,688,239 | 1,658,866 |
| Net property, plant and equipment | 5,595,294 | 5,475,604 |
| Current assets | | |
| Cash and cash equivalents | 124,601 | 64,239 |
| Accounts receivable, net | 500,863 | 234,526 |
| Gas stored underground | 274,126 | 256,415 |
| Other current assets | 265,044 | 272,782 |
| Total current assets | 1,164,634 | 827,962 |
| Goodwill and intangible assets | 740,836 | 740,847 |
| Deferred charges and other assets | 463,454 | 451,262 |
| | $7,964,218 | $7,495,675 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2012 — 90,516,948 shares September 30, 2012 — 90,239,900 shares | $ 453 | $ 451 |
| Additional paid-in capital | 1,750,195 | 1,745,467 |
| Retained earnings | 709,438 | 660,932 |
| Accumulated other comprehensive loss | (36,081) | (47,607) |
| Shareholders' equity | 2,424,005 | 2,359,243 |
| Long-term debt | 1,956,376 | 1,956,305 |
| Total capitalization | 4,380,381 | 4,315,548 |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 367,312 | 215,229 |
| Other current liabilities | 446,717 | 489,665 |
| Short-term debt | 830,891 | 570,929 |
| Current maturities of long-term debt | 131 | 131 |
| Total current liabilities | 1,645,051 | 1,275,954 |
| Deferred income taxes | 1,066,273 | 1,015,083 |
| Regulatory cost of removal obligation | 371,608 | 381,164 |
| Pension and postretirement costs | 456,694 | 457,196 |
| Deferred credits and other liabilities | 44,211 | 50,730 |
| | $7,964,218 | $7,495,675 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $ 666,787 | $ 676,113 |
| Regulated transmission and storage segment | 60,681 | 56,759 |
| Nonregulated segment | 399,894 | 444,176 |
| Intersegment eliminations | (93,207) | (93,054) |
| | 1,034,155 | 1,083,994 |
| Purchased gas cost | | |
| Natural gas distribution segment | 387,156 | 392,518 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 377,435 | 428,771 |
| Intersegment eliminations | (92,798) | (92,687) |
| | 671,793 | 728,602 |
| Gross profit | 362,362 | 355,392 |
| Operating expenses | | |
| Operation and maintenance | 106,527 | 114,644 |
| Depreciation and amortization | 59,579 | 58,366 |
| Taxes, other than income | 41,334 | 42,911 |
| Total operating expenses | 207,440 | 215,921 |
| Operating income | 154,922 | 139,471 |
| Miscellaneous income (expense) | 698 | (2,016) |
| Interest charges | 30,522 | 35,726 |
| Income from continuing operations before income taxes | 125,098 | 101,729 |
| Income tax expense | 47,750 | 39,345 |
| Income from continuing operations | 77,348 | 62,384 |
| Income from discontinued operations, net of tax ($1,728 and $3,516) | 3,117 | 6,123 |
| Net income | $ 80,465 | $ 68,507 |
| Basic earnings per share | | |
| Income per share from continuing operations | $ 0.85 | $ 0.68 |
| Income per share from discontinued operations | 0.04 | 0.07 |
| Net income per share — basic | $ 0.89 | $ 0.75 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 0.85 | $ 0.68 |
| Income per share from discontinued operations | 0.03 | 0.07 |
| Net income per share — diluted | $ 0.88 | $ 0.75 |
| Cash dividends per share | $ 0.350 | $ 0.345 |
| Weighted average shares outstanding: | | |
| Basic | 90,359 | 90,254 |
| Diluted | 91,309 | 90,546 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands) | |
| Net income | $80,465 | $ 68,507 |
| Other comprehensive income (loss), net of tax | | |
| Unrealized holding gains (losses) on available-for-sale securities, net of tax of $(220) and $514 | (373) | 901 |
| Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $7,049 and $(638) | 12,264 | (1,087) |
| Net unrealized losses on commodity cash flow hedges, net of tax of $(233) and $(10,597) | (365) | (16,575) |
| Total other comprehensive income (loss) | 11,526 | (16,761) |
| Total comprehensive income | $91,991 | $ 51,746 |

See accompanying notes to condensed consolidated financial statements

# ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands) | |
| Cash Flows From Operating Activities | | |
| Net income | $ 80,465 | $ 68,507 |
| Adjustments to reconcile net income to net cash provided (used) by operating activities: | | |
| Depreciation and amortization: | | |
| Charged to depreciation and amortization | 60,500 | 60,733 |
| Charged to other accounts | 128 | 78 |
| Deferred income taxes | 45,951 | 40,042 |
| Other | 3,242 | 4,692 |
| Net assets / liabilities from risk management activities | (15,641) | (8,426) |
| Net change in operating assets and liabilities | (144,787) | (180,917) |
| Net cash provided (used) by operating activities | 29,858 | (15,291) |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (190,027) | (154,394) |
| Other, net | (1,273) | (1,080) |
| Net cash used in investing activities | (191,300) | (155,474) |
| Cash Flows From Financing Activities | | |
| Net increase in short-term debt | 256,933 | 173,905 |
| Repayment of long-term debt | — | (2,303) |
| Cash dividends paid | (31,992) | (31,517) |
| Repurchase of common stock | — | (12,535) |
| Repurchase of equity awards | (3,124) | (3,120) |
| Issuance of common stock | (13) | 76 |
| Net cash provided by financing activities | 221,804 | 124,506 |
| Net increase (decrease) in cash and cash equivalents | 60,362 | (46,259) |
| Cash and cash equivalents at beginning of period | 64,239 | 131,419 |
| Cash and cash equivalents at end of period | $ 124,601 | $ 85,160 |

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2012

## 1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company"), headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. For the fiscal year ended September 30, 2012, our regulated businesses comprised over 95 percent of our consolidated net income.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in nine states. In addition, we transport natural gas for others through our distribution system. In August 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. After the closing of this transaction, which we currently anticipate will occur during the third quarter of fiscal 2013, we will operate in eight states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

We operate the Company through the following three segments:

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

## 2. Unaudited Interim Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2012 are not indicative of our results of operations for the full 2013 fiscal year, which ends September 30, 2013.

We have evaluated subsequent events from the December 31, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as discussed in Note 3, Note 6 and Note 9, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

***Significant accounting policies***

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012.

Due to the pending sale of our distribution operations in our Georgia service area, the financial results for this service area are shown in discontinued operations. Accordingly, certain prior-year amounts have been reclassified to conform with the current-year presentation.

Due to accounting guidance that became effective for us on October 1, 2012, we have begun presenting the components of other comprehensive income and total comprehensive income in a separate condensed consolidated statement of comprehensive income immediately following the condensed consolidated statement of income. During the three months ended December 31, 2012, there were no other significant changes to our accounting policies.

***Regulatory assets and liabilities***

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2012 and September 30, 2012 included the following:

| | December 31, 2012 | September 30, 2012 |
|---|---|---|
| | (In thousands) | |
| **Regulatory assets:** | | |
| Pension and postretirement benefit costs[1] | $295,277 | $296,160 |
| Merger and integration costs, net | 5,628 | 5,754 |
| Deferred gas costs | 28,351 | 31,359 |
| Regulatory cost of removal asset | 10,401 | 10,500 |
| Rate case costs | 5,726 | 4,661 |
| Deferred franchise fees | 819 | 2,714 |
| Texas Rule 8.209[2] | 9,734 | 5,370 |
| APT annual adjustment mechanism | 3,973 | 4,539 |
| Other | 6,973 | 7,262 |
| | $366,882 | $368,319 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 8,290 | $ 23,072 |
| Regulatory cost of removal obligation | 450,968 | 459,688 |
| Other | 5,534 | 5,637 |
| | $464,792 | $488,397 |

(1) Includes $11.5 million and $7.6 million of pension and post-retirement expense deferred in our Texas service areas pursuant to the Texas Gas Utility Regulatory Act.

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

The amounts above do not include regulatory assets and liabilities related to our Georgia service area, which are classified as assets held for sale as discussed in Note 5.

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

***Accumulated Other Comprehensive Income***

Accumulated other comprehensive loss, net of tax, as of December 31, 2012 and September 30, 2012 consisted of the following unrealized gains (losses):

| | December 31, 2012 | September 30, 2012 |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive loss: | | |
| Unrealized holding gains on available-for-sale securities | $ 5,288 | $ 5,661 |
| Interest rate agreements | (32,009) | (44,273) |
| Commodity cash flow hedges | (9,360) | (8,995) |
| | $(36,081) | $(47,607) |

## 3. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. During the first quarter, there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

***Regulated Commodity Risk Management Activities***

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2012-2013 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 33 percent, or 22.6 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

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

***Nonregulated Commodity Risk Management Activities***

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

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 60 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in asset optimization activities in our nonregulated segment.

Our nonregulated operations also use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.

***Interest Rate Risk Management Activities***

We have periodically managed interest rate risk by entering into financial instruments to fix the Treasury yield component of the interest cost associated with anticipated financings. Prior to fiscal 2012, we used Treasury locks to mitigate interest rate risk; however, beginning in the fourth quarter of fiscal 2012 we started utilizing interest rate swaps and forward starting interest rate swaps to manage this risk.

In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $350 million of a total $500 million of senior notes that were issued on January 11,

2013. This offering is discussed in Note 6. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on January 8, 2013 with the payment of $66.7 million to the counterparties due to a decrease in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the $66.7 million unrealized loss was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

In the fourth quarter of fiscal 2012, we entered into an interest rate swap to fix the LIBOR component of our $260 million short-term financing facility that terminated on December 27, 2012. We recorded an immaterial loss upon settlement of the swap, which was recorded as a component of interest expense as we did not designate the interest rate swap as a hedge.

In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred will be reported as a component of interest expense.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. As of December 31, 2012, the remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

***Quantitative Disclosures Related to Financial Instruments***

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

As of December 31, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

| Contract Type | Hedge Designation | Natural Gas Distribution | Nonregulated |
|---|---|---|---|
| | | Quantity (MMcf) | |
| Commodity contracts | Fair Value | — | (26,450) |
| | Cash Flow | — | 28,718 |
| | Not designated | 12,479 | 55,915 |
| | | 12,479 | 58,183 |

*Impact of Financial Instruments on the Balance Sheet*

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2012 and September 30, 2012. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $16.6 million and $23.7 million of cash held on deposit as of December 31, 2012 and September 30, 2012 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **December 31, 2012:** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 20,103 | $ 20,103 |
| Noncurrent commodity contracts | Deferred charges and other assets | 10,849 | 699 | 11,548 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (77,078) | (17,995) | (95,073) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (4,084) | (4,084) |
| **Total** | | (66,229) | (1,277) | (67,506) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 1,773 | 94,168 | 95,941 |
| Noncurrent commodity contracts | Deferred charges and other assets | 761 | 59,791 | 60,552 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[1] | (502) | (94,978) | (95,480) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (59,266) | (59,266) |
| **Total** | | 2,032 | (285) | 1,747 |
| **Total Financial Instruments** | | $(64,197) | $ (1,562) | $(65,759) |

[1] Other current liabilities not designated as hedges in our natural gas distribution segment include $0.1 million related to risk management liabilities that were classified as assets held for sale at December 31, 2012.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **September 30, 2012:** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 19,301 | $ 19,301 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 1,923 | 1,923 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (85,040) | (23,787) | (108,827) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (4,999) | (4,999) |
| **Total** | | (85,040) | (7,562) | (92,602) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets[1] | 7,082 | 98,393 | 105,475 |
| Noncurrent commodity contracts | Deferred charges and other assets | 2,283 | 60,932 | 63,215 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[2] | (585) | (99,824) | (100,409) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (67,062) | (67,062) |
| **Total** | | 8,780 | (7,561) | 1,219 |
| **Total Financial Instruments** | | $(76,260) | $(15,123) | $ (91,383) |

(1) Other current assets not designated as hedges in our natural gas distribution segment include $0.1 million related to risk management assets that were classified as assets held for sale at September 30, 2012.

(2) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2012.

*Impact of Financial Instruments on the Income Statement*

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2012 and 2011 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $16.1 million and $8.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

*Fair Value Hedges*

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2012 and 2011 is presented below.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Commodity contracts | $ 7,314 | $ 24,064 |
| Fair value adjustment for natural gas inventory designated as the hedged item | 8,818 | (15,249) |
| Total decrease in purchased gas cost | $16,132 | $ 8,815 |
| The decrease in purchased gas cost is comprised of the following: | | |
| Basis ineffectiveness | $ (241) | $ 841 |
| Timing ineffectiveness | 16,373 | 7,974 |
| | $16,132 | $ 8,815 |

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. We did not record a writedown for nonqualifying natural gas inventory for the three months ended December 31, 2012. During the three months ended December 31, 2011, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market.

*Cash Flow Hedges*

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2012 and 2011 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | Three Months Ended December 31, 2012 | | |
|---|---|---|---|
| | Natural Gas Distribution | Nonregulated | Consolidated |
| | | (In thousands) | |
| Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts | $ — | $(5,160) | $(5,160) |
| Loss arising from ineffective portion of commodity contracts | — | (19) | (19) |
| Total impact on purchased gas cost | — | (5,179) | (5,179) |
| Loss on settled interest rate agreements reclassified from AOCI into interest expense | (502) | — | (502) |
| Total Impact from Cash Flow Hedges | $(502) | $(5,179) | $(5,681) |

| | Three Months Ended December 31, 2011 | | |
|---|---|---|---|
| | Natural Gas Distribution | Nonregulated | Consolidated |
| | | (In thousands) | |
| Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts | $ — | $(11,642) | $(11,642) |
| Loss arising from ineffective portion of commodity contracts | — | (430) | (430) |
| Total impact on purchased gas cost | — | (12,072) | (12,072) |
| Loss on settled interest rate agreements reclassified from AOCI into interest expense | (502) | — | (502) |
| Total Impact from Cash Flow Hedges | $(502) | $(12,072) | $(12,574) |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| *Increase (decrease) in fair value:* | | |
| Interest rate agreements | $11,945 | $ (1,403) |
| Forward commodity contracts | (3,513) | (23,678) |
| *Recognition of losses in earnings due to settlements:* | | |
| Interest rate agreements | 319 | 316 |
| Forward commodity contracts | 3,148 | 7,103 |
| Total other comprehensive income (loss) from hedging, net of tax[1] | $11,899 | $(17,662) |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our Treasury lock and interest rate swap agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred gains (losses) associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2012. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock and interest rate swap agreements as those instruments have not yet settled.

| | Interest Rate Agreements | Commodity Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| Next twelve months | $ (1,276) | $(7,342) | $(8,618) |
| Thereafter | 11,322 | (2,018) | 9,304 |
| Total[1] | $10,046 | $(9,360) | $ 686 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

*Impact of Financial Instruments Not Designated as Hedges*

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statement for the three months ended December 31, 2012 and 2011 was a decrease in revenue of $0.1 million and $2.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

## 4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. During the first quarter of fiscal 2013, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2012.

### *Quantitative Disclosures*

*Financial Instruments*

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and September 30, 2012. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[1] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[2] | December 31, 2012 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 13,383 | $ — | $ — | $ 13,383 |
| Nonregulated segment | 1,043 | 173,718 | — | (156,904) | 17,857 |
| Total financial instruments | 1,043 | 187,101 | — | (156,904) | 31,240 |
| Hedged portion of gas stored underground | 87,401 | — | — | — | 87,401 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 801 | — | — | 801 |
| Registered investment companies | 39,499 | — | — | — | 39,499 |
| Bonds | — | 23,565 | — | — | 23,565 |
| Total available-for-sale securities | 39,499 | 24,366 | — | — | 63,865 |
| Total assets | $127,943 | $211,467 | $ — | $(156,904) | $182,506 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 77,580 | $ — | $ — | $ 77,580 |
| Nonregulated segment | 1,261 | 175,062 | — | (173,463) | 2,860 |
| Total liabilities | $ 1,261 | $252,642 | $ — | $(173,463) | $ 80,440 |

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)(1) | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral(3) | September 30, 2012 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 9,365 | $ — | $ — | $ 9,365 |
| Nonregulated segment | 714 | 179,835 | — | (162,776) | 17,773 |
| Total financial instruments | 714 | 189,200 | — | (162,776) | 27,138 |
| Hedged portion of gas stored underground | 67,192 | — | — | — | 67,192 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 1,634 | — | — | 1,634 |
| Registered investment companies | 40,212 | — | — | — | 40,212 |
| Bonds | — | 22,552 | — | — | 22,552 |
| Total available-for-sale securities | 40,212 | 24,186 | — | — | 64,398 |
| Total assets | $108,118 | $213,386 | $ — | $(162,776) | $158,728 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 85,625 | $ — | $ — | $ 85,625 |
| Nonregulated segment | 4,563 | 191,109 | — | (186,451) | 9,221 |
| Total liabilities | $ 4,563 | $276,734 | $ — | $(186,451) | $ 94,846 |

(1) Our Level 2 measurements consist of over-the-counter options and swaps, which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds, which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2012, we had $16.6 million of cash held in margin accounts to collateralize certain financial instruments, which amount is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2012 we had $23.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting arrangements and the remaining $17.8 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

| | Amortized Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| | | (In thousands) | | |
| **As of December 31, 2012** | | | | |
| Domestic equity mutual funds | $25,645 | $7,209 | $— | $32,854 |
| Foreign equity mutual funds | 5,568 | 1,077 | — | 6,645 |
| Bonds | 23,387 | 180 | (2) | 23,565 |
| Money market funds | 801 | — | — | 801 |
| | $55,401 | $8,466 | $ (2) | $63,865 |
| **As of September 30, 2012** | | | | |
| Domestic equity mutual funds | $25,779 | $8,183 | $— | $33,962 |
| Foreign equity mutual funds | 5,568 | 682 | — | 6,250 |
| Bonds | 22,358 | 196 | (2) | 22,552 |
| Money market funds | 1,634 | — | — | 1,634 |
| | $55,339 | $9,061 | $ (2) | $64,398 |

At December 31, 2012 and September 30, 2012, our available-for-sale securities included $40.3 million and $41.8 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2012, we maintained investments in bonds that have contractual maturity dates ranging from January 2013 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

*Other Fair Value Measures*

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of December 31, 2012:

| | December 31, 2012 |
|---|---|
| | (In thousands) |
| Carrying Amount | $1,960,131 |
| Fair Value | $2,403,501 |

## 5. Discontinued Operations

On August 8, 2012, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. We currently anticipate the transaction will close during the third quarter of fiscal 2013.

As required under generally accepted accounting principles, the operating results of our discontinued operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. For the three months ended December 31, 2012, net income for discontinued operations includes the operating results of our Georgia operations. For the three months ended December 31, 2011, net income from discontinued operations includes the operating results of our Georgia operations and the operating results of our Missouri, Illinois and Iowa operations that were sold on August 1, 2012. Expenses related to general corporate overhead and interest expense allocated to the operations of these service areas are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Georgia operations are classified as "held for sale" in other current assets and liabilities in our consolidated balance sheets at December 31, 2012 and September 30, 2012. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Operating revenues | $16,284 | $40,630 |
| Purchased gas cost | 8,967 | 24,640 |
| Gross profit | 7,317 | 15,990 |
| Operating expenses | 2,820 | 6,728 |
| Operating income | 4,497 | 9,262 |
| Other nonoperating income | 348 | 377 |
| Income from discontinued operations before income taxes | 4,845 | 9,639 |
| Income tax expense | 1,728 | 3,516 |
| Net income | $ 3,117 | $ 6,123 |

The following table presents balance sheet data related to assets held for sale.

| | December 31, 2012 | September 30, 2012 |
|---|---|---|
| | (In thousands) | |
| Net plant, property & equipment | $141,850 | $142,865 |
| Gas stored underground | 5,320 | 4,688 |
| Other current assets | 11,605 | 6,931 |
| Deferred charges and other assets | 45 | 87 |
| Assets held for sale | $158,820 | $154,571 |
| Accounts payable and accrued liabilities | $ 3,705 | $ 2,114 |
| Other current liabilities | 3,265 | 3,776 |
| Regulatory cost of removal obligation | 3,525 | 3,257 |
| Deferred credits and other liabilities | 417 | 2,426 |
| Liabilities held for sale | $ 10,912 | $ 11,573 |

## 6. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. Except as discussed below, there were no material changes in the terms of our debt instruments during the three months ended December 31, 2012.

### *Long-term debt*

Long-term debt at December 31, 2012 and September 30, 2012 consisted of the following:

| | December 31, 2012 | September 30, 2012 |
|---|---|---|
| | (In thousands) | |
| Unsecured 4.95% Senior Notes, due 2014 | $ 500,000 | $ 500,000 |
| Unsecured 6.35% Senior Notes, due 2017 | 250,000 | 250,000 |
| Unsecured 8.50% Senior Notes, due 2019 | 450,000 | 450,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Unsecured 5.50% Senior Notes, due 2041 | 400,000 | 400,000 |
| Medium term notes | | |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| Rental property term note due in installments through 2013 | 131 | 131 |
| Total long-term debt | 1,960,131 | 1,960,131 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | 3,624 | 3,695 |
| Current maturities | 131 | 131 |
| | $1,956,376 | $1,956,305 |

Our $250 million Unsecured 5.125% Senior Notes were originally scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On

September 27, 2012, we entered into a $260 million short-term financing facility that was scheduled to mature on February 1, 2013 to repay the commercial paper borrowings utilized to redeem the Unsecured 5.125% Senior Notes. The short-term facility was repaid with the proceeds received through the issuance of 30-year unsecured senior notes on January 11, 2013, as discussed below.

We issued $500 million Unsecured 4.15% Senior Notes on January 11, 2013. The effective interest rate of these notes is 4.64 percent, after giving effect to offering costs and the settlement of the associated Treasury locks discussed in Note 3. Of the net proceeds of approximately $494 million, $260 million was used to repay our short-term financing facility. The remaining $234 million of net proceeds was used to partially repay our commercial paper borrowings and for general corporate purposes.

***Short-term debt***

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We currently finance our short-term borrowing requirements through a combination of a $750 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. On December 7, 2012, we amended the terms of our former $750 million unsecured credit facility to increase the borrowing capacity to $950 million, with an accordion feature, which, if utilized, would increase the borrowing capacity to $1.2 billion. The amendment also permits us to obtain same-day funding on base rate loans. There were no other material changes to the credit facility. These facilities provide approximately $1.0 billion of working capital funding. At December 31, 2012 and September 30, 2012, there was $570.9 million and $310.9 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

***Regulated Operations***

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $989 million of working capital funding, including a five-year $950 million unsecured facility, a $25 million unsecured facility and a $14 million revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $14 million revolving credit facility was $2.5 million at December 31, 2012.

In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH, which bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2013.

***Nonregulated Operations***

Prior to December 5, 2012, Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, had a three-year $200 million committed revolving credit facility, expiring in December 2014, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility was primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility was collateralized by substantially all of the assets of AEM and was guaranteed by AEH. AEM terminated the committed revolving credit facility on December 5, 2012, primarily in order to reduce external credit expense. AEM incurred no penalties in connection with the termination. This facility was replaced with two $25 million, 364-day bilateral credit facilities, one of which is a committed facility. These facilities will be used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $40.0 million at December 31, 2012.

AEH has a $500 million intercompany demand credit facility with AEC. This facility bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2013.

### *Shelf Registration*

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At December 31, 2012, $900 million remained available for issuance under the shelf until it expires on March 31, 2013. However, with the issuance of $500 million of long-term debt on January 11, 2013, as described above, our remaining availability has been reduced to $400 million. We intend to file a new shelf registration statement with the SEC for $1.75 billion prior to the expiration of the current shelf registration statement.

### *Debt Covenants*

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2012, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 55 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these financial covenants, our credit facilities and public debt indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

We were in compliance with all of our debt covenants as of December 31, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

## 7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2012 and 2011 are calculated as follows:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands, except per share amounts) | |
| **Basic Earnings Per Share from continuing operations** | | |
| Income from continuing operations | $77,348 | $62,384 |
| Less: Income from continuing operations allocated to participating securities | 260 | 650 |
| Income from continuing operations available to common shareholders | $77,088 | $61,734 |
| Basic weighted average shares outstanding | 90,359 | 90,254 |
| Income from continuing operations per share — Basic | $ 0.85 | $ 0.68 |
| **Basic Earnings Per Share from discontinued operations** | | |
| Income from discontinued operations | $ 3,117 | $ 6,123 |
| Less: Income from discontinued operations allocated to participating securities | 10 | 64 |
| Income from discontinued operations available to common shareholders | $ 3,107 | $ 6,059 |
| Basic weighted average shares outstanding | 90,359 | 90,254 |
| Income from discontinued operations per share — Basic | $ 0.04 | $ 0.07 |
| Net income per share — Basic | $ 0.89 | $ 0.75 |

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands, except per share amounts) | |
| **Diluted Earnings Per Share from continuing operations** | | |
| Income from continuing operations available to common shareholders | $77,088 | $61,734 |
| Effect of dilutive stock options and other shares | 2 | 1 |
| Income from continuing operations available to common shareholders | $77,090 | $61,735 |
| Basic weighted average shares outstanding | 90,359 | 90,254 |
| Additional dilutive stock options and other shares | 950 | 292 |
| Diluted weighted average shares outstanding | 91,309 | 90,546 |
| Income from continuing operations per share — Diluted | $ 0.85 | $ 0.68 |
| **Diluted Earnings Per Share from discontinued operations** | | |
| Income from discontinued operations available to common shareholders | $ 3,107 | $ 6,059 |
| Effect of dilutive stock options and other shares | — | — |
| Income from discontinued operations available to common shareholders | $ 3,107 | $ 6,059 |
| Basic weighted average shares outstanding | 90,359 | 90,254 |
| Additional dilutive stock options and other shares | 950 | 292 |
| Diluted weighted average shares outstanding | 91,309 | 90,546 |
| Income from discontinued operations per share — Diluted | $ 0.03 | $ 0.07 |
| Net income per share — Diluted | $ 0.88 | $ 0.75 |

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2012 and 2011 as their exercise price was less than the average market price of the common stock during that period.

## 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 December 31, 2012 and 2011 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

| | Three Months Ended December 31 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 5,202 | $ 4,298 | $4,700 | $4,088 |
| Interest cost | 6,025 | 6,677 | 3,241 | 3,465 |
| Expected return on assets | (5,739) | (5,368) | (997) | (652) |
| Amortization of transition asset | — | — | 270 | 378 |
| Amortization of prior service cost | (35) | (35) | (362) | (362) |
| Amortization of actuarial loss | 5,561 | 4,142 | 1,049 | 662 |
| Net periodic pension cost | $11,014 | $ 9,714 | $7,901 | $7,579 |

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2012 and 2011 are as follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Discount rate | 4.04% | 5.05% | 4.04% | 5.05% |
| Rate of compensation increase | 3.50% | 3.50% | N/A | N/A |
| Expected return on plan assets | 7.75% | 7.75% | 4.70% | 4.70% |

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. We contributed $6.2 million to our pension plans during the three months ended December 31, 2012. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2013. We expect to contribute a total of between $30 million and $40 million to our pension plans during fiscal 2013.

We contributed $6.2 million to our other post-retirement benefit plans during the three months ended December 31, 2012. We expect to contribute a total of between $25 million and $30 million to these plans during fiscal 2013.

## 9. Commitments and Contingencies

### *Litigation and Environmental Matters*

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2012.

Since September 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

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

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

The landowners and investors/working interest owners may seek discretionary review from the Supreme Court of Kentucky. The decision of the Court of Appeals will not become final until that process is completed. We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter and we will continue to maintain this amount in legal reserves until the appellate process in this case has been completed. We continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

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

### *Purchase Commitments*

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2012, AEH was committed to purchase 67.2 Bcf within one year, 25.1 Bcf within one to three years and 26.5 Bcf after three years under indexed contracts. AEH is committed to purchase 3.7 Bcf within one year and less than 0.1 Bcf within one to three years under fixed price contracts with prices ranging from \$2.98 to \$6.36 per Mcf. Purchases under these contracts totaled \$289.5 million and \$312.1 million for the three months ended December 31, 2012 and 2011.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of December 31, 2012 are as follows (in thousands):

| | |
|---|---|
| 2013 | \$174,615 |
| 2014 | 73,682 |
| 2015 | — |
| 2016 | — |
| 2017 | — |
| Thereafter | — |
| | \$248,297 |

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. There were no material changes to the estimated storage and transportation fees for the quarter ended December 31, 2012.

### *Regulatory Matters*

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC and SEC have issued a number of rules and regulations, we expect additional rules and regulations to be adopted, which should provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business have been increased as a result of the new legislation and related rules and regulations. We also anticipate additional reporting and disclosure obligations will be imposed through the adoption of additional rules and regulations.

As of December 31, 2012, rate proceedings were in progress in our Kansas, Colorado, Louisiana and Georgia service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

## 10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. During the three months ended December 31, 2012, there were no material changes in our concentration of credit risk.

## 11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2012 and 2011 by segment are presented in the following tables:

| | Three Months Ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $665,549 | $18,699 | $349,907 | $ — | $1,034,155 |
| Intersegment revenues | 1,238 | 41,982 | 49,987 | (93,207) | — |
| | 666,787 | 60,681 | 399,894 | (93,207) | 1,034,155 |
| Purchased gas cost | 387,156 | — | 377,435 | (92,798) | 671,793 |
| Gross profit | 279,631 | 60,681 | 22,459 | (409) | 362,362 |
| Operating expenses | | | | | |
| Operation and maintenance | 83,736 | 16,320 | 6,882 | (411) | 106,527 |
| Depreciation and amortization | 50,060 | 8,390 | 1,129 | — | 59,579 |
| Taxes, other than income | 36,751 | 3,949 | 634 | — | 41,334 |
| Total operating expenses | 170,547 | 28,659 | 8,645 | (411) | 207,440 |
| Operating income | 109,084 | 32,022 | 13,814 | 2 | 154,922 |
| Miscellaneous income (expense) | (131) | (127) | 1,667 | (711) | 698 |
| Interest charges | 23,563 | 6,871 | 797 | (709) | 30,522 |
| Income from continuing operations before income taxes | 85,390 | 25,024 | 14,684 | — | 125,098 |
| Income tax expense | 32,297 | 8,919 | 6,534 | — | 47,750 |
| Income from continuing operations | 53,093 | 16,105 | 8,150 | — | 77,348 |
| Income from discontinued operations, net of tax | 3,117 | — | — | — | 3,117 |
| Net income | $ 56,210 | $16,105 | $ 8,150 | $ — | $ 80,465 |
| Capital expenditures | $145,871 | $43,831 | $ 325 | $ — | $ 190,027 |

| | Three Months Ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $675,889 | $19,440 | $388,665 | $ — | $1,083,994 |
| Intersegment revenues | 224 | 37,319 | 55,511 | (93,054) | — |
| | 676,113 | 56,759 | 444,176 | (93,054) | 1,083,994 |
| Purchased gas cost | 392,518 | — | 428,771 | (92,687) | 728,602 |
| Gross profit | 283,595 | 56,759 | 15,405 | (367) | 355,392 |
| Operating expenses | | | | | |
| Operation and maintenance | 91,996 | 16,965 | 6,051 | (368) | 114,644 |
| Depreciation and amortization | 49,982 | 7,651 | 733 | — | 58,366 |
| Taxes, other than income | 38,192 | 3,784 | 935 | — | 42,911 |
| Total operating expenses | 180,170 | 28,400 | 7,719 | (368) | 215,921 |
| Operating income | 103,425 | 28,359 | 7,686 | 1 | 139,471 |
| Miscellaneous income (expense) | (1,897) | (280) | 36 | 125 | (2,016) |
| Interest charges | 28,139 | 7,209 | 252 | 126 | 35,726 |
| Income from continuing operations before income taxes | 73,389 | 20,870 | 7,470 | — | 101,729 |
| Income tax expense | 28,888 | 7,456 | 3,001 | — | 39,345 |
| Income from continuing operations | 44,501 | 13,414 | 4,469 | — | 62,384 |
| Income from discontinued operations, net of tax | 6,123 | — | — | — | 6,123 |
| Net income | $ 50,624 | $13,414 | $ 4,469 | $ — | $ 68,507 |
| Capital expenditures | $128,733 | $24,120 | $ 1,541 | $ — | $ 154,394 |

Balance sheet information at December 31, 2012 and September 30, 2012 by segment is presented in the following tables.

| | December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,523,922 | $1,007,904 | $ 63,468 | $ — | $5,595,294 |
| Investment in subsidiaries | 771,387 | — | (2,096) | (769,291) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 77,136 | — | 47,465 | — | 124,601 |
| Assets from risk management activities | 1,773 | — | 17,857 | — | 19,630 |
| Other current assets | 770,366 | 14,632 | 471,582 | (236,177) | 1,020,403 |
| Intercompany receivables | 624,637 | — | — | (624,637) | — |
| Total current assets | 1,473,912 | 14,632 | 536,904 | (860,814) | 1,164,634 |
| Intangible assets | — | — | 153 | — | 153 |
| Goodwill | 573,550 | 132,422 | 34,711 | — | 740,683 |
| Noncurrent assets from risk management activities | 11,610 | — | — | — | 11,610 |
| Deferred charges and other assets | 429,252 | 15,787 | 6,805 | — | 451,844 |
| | $7,783,633 | $1,170,745 | $639,945 | $(1,630,105) | $7,964,218 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,424,005 | $ 344,266 | $427,121 | $ (771,387) | $2,424,005 |
| Long-term debt | 1,956,376 | — | — | — | 1,956,376 |
| Total capitalization | 4,380,381 | 344,266 | 427,121 | (771,387) | 4,380,381 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | — | — | 131 | — | 131 |
| Short-term debt | 1,045,180 | — | — | (214,289) | 830,891 |
| Liabilities from risk management activities | 77,500 | — | — | — | 77,500 |
| Other current liabilities | 590,710 | 13,470 | 152,141 | (19,792) | 736,529 |
| Intercompany payables | — | 573,006 | 51,631 | (624,637) | — |
| Total current liabilities | 1,713,390 | 586,476 | 203,903 | (858,718) | 1,645,051 |
| Deferred income taxes | 823,073 | 238,285 | 4,915 | — | 1,066,273 |
| Noncurrent liabilities from risk management activities | — | — | 2,860 | — | 2,860 |
| Regulatory cost of removal obligation | 371,608 | — | — | — | 371,608 |
| Deferred credits and other liabilities | 495,181 | 1,718 | 1,146 | — | 498,045 |
| | $7,783,633 | $1,170,745 | $639,945 | $(1,630,105) | $7,964,218 |

| | September 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,432,017 | $ 979,443 | $ 64,144 | $ — | $5,475,604 |
| Investment in subsidiaries | 747,496 | — | (2,096) | (745,400) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 12,787 | — | 51,452 | — | 64,239 |
| Assets from risk management activities | 6,934 | — | 17,773 | — | 24,707 |
| Other current assets | 546,187 | 11,788 | 404,097 | (223,056) | 739,016 |
| Intercompany receivables | 636,557 | — | — | (636,557) | — |
| Total current assets | 1,202,465 | 11,788 | 473,322 | (859,613) | 827,962 |
| Intangible assets | — | — | 164 | — | 164 |
| Goodwill | 573,550 | 132,422 | 34,711 | — | 740,683 |
| Noncurrent assets from risk management activities | 2,283 | — | — | — | 2,283 |
| Deferred charges and other assets | 417,893 | 24,353 | 6,733 | — | 448,979 |
| | $7,375,704 | $1,148,006 | $576,978 | $(1,605,013) | $7,495,675 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,359,243 | $ 328,161 | $419,335 | $ (747,496) | $2,359,243 |
| Long-term debt | 1,956,305 | — | — | — | 1,956,305 |
| Total capitalization | 4,315,548 | 328,161 | 419,335 | (747,496) | 4,315,548 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | — | — | 131 | — | 131 |
| Short-term debt | 782,719 | — | — | (211,790) | 570,929 |
| Liabilities from risk management activities | 85,366 | — | 15 | — | 85,381 |
| Other current liabilities | 526,089 | 12,478 | 90,116 | (9,170) | 619,513 |
| Intercompany payables | — | 584,578 | 51,979 | (636,557) | — |
| Total current liabilities | 1,394,174 | 597,056 | 142,241 | (857,517) | 1,275,954 |
| Deferred income taxes | 789,288 | 220,647 | 5,148 | — | 1,015,083 |
| Noncurrent liabilities from risk management activities | — | — | 9,206 | — | 9,206 |
| Regulatory cost of removal obligation | 381,164 | — | — | — | 381,164 |
| Deferred credits and other liabilities | 495,530 | 2,142 | 1,048 | — | 498,720 |
| | $7,375,704 | $1,148,006 | $576,978 | $(1,605,013) | $7,495,675 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2012, the related condensed consolidated statements of income and comprehensive income for the three-month periods ended December 31, 2012 and 2011, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2012 and 2011. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2012, 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 12, 2012, 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, 2012, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 7, 2013

**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, 2012.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

## OVERVIEW

Atmos Energy and its subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in nine states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In August 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. After the closing of this transaction, which we currently anticipate will occur during the third quarter of fiscal 2013, we will operate in eight states.

Through our nonregulated businesses, we provide natural gas management and transportation services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and

Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties.

As discussed in Note 11, we operate the Company through the following three segments:

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

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012 and include the following:

- Regulation
- Unbilled revenue
- Financial instruments and hedging activities
- Fair value measurements
- Impairment assessments
- Pension and other postretirement plans
- Contingencies

Our critical accounting policies are reviewed periodically by the Audit Committee. There were no significant changes to these critical accounting policies during the three months ended December 31, 2012.

## RESULTS OF OPERATIONS

We reported net income of $80.5 million, or $0.88 per diluted share for the three months ended December 31, 2012 compared with net income of $68.5 million, or $0.75 per diluted share in the prior-year quarter. Regulated operations contributed 90 percent of our net income during this period with our nonregulated operations contributing the remaining ten percent. Excluding the impact of unrealized margins, diluted earnings per share increased $0.13 compared with the prior-year quarter. The $0.13 per diluted share increase primarily reflects recent rate increases approved in our regulated transmission and storage segment and improved asset optimization margins in our nonregulated segment, coupled with an $8.1 million decrease in operating and maintenance expense and a $5.2 million decrease in interest expense due primarily from interest capitalized related to Rule 8.209 spending in the current quarter and the early redemption of the 5.125% $250 million senior notes due January 2013, with funds borrowed under a $260 million short-term debt facility in August 2012.

Due to the pending sale of our Georgia service area, the results of operations for this service area are shown in discontinued operations for both periods presented. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The sale of these three service areas was completed in August 2012. During the current-year quarter, discontinued operations generated net income of $3.1 million, or $0.03 per diluted share, compared with net income of $6.1 million, or $0.07 per diluted share in the prior-year quarter. Continuing operations in the current quarter generated net income of $77.3 million, or $0.85 per diluted share, compared with net income of $62.4 million, or $0.68 per diluted share in the prior-year quarter.

During the first quarter of fiscal 2013, we completed seven regulatory proceedings, which should result in a $63.7 million increase in annual operating income. The majority of this rate increase related to our Mid-Tex Division, where rates became effective January 1, 2013. The rate design approved in our Mid-Tex Division and West Texas Division regulatory proceedings includes an increase to the base customer charge and a decrease in the commodity charge applied to customer consumption. The effect of this change in rate design allows the Company's rates to be more closely aligned with utility industry standard rate design. In addition, we anticipate these divisions will earn their operating income more ratably over the fiscal year as we are now less dependent on customer consumption. Therefore, we anticipate operating income earned during the first and second quarters to be lower than in previous periods with operating income earned during the third and fourth quarters to be higher than in previous periods. Accordingly, we anticipate our fiscal 2013 period-over-period results will reflect the impact of these rate design changes.

We also took several steps during the first quarter and early part of the second quarter to further strengthen our balance sheet and borrowing capability. In December 2012, we amended our $750 million revolving credit agreement primarily to (i) increase our borrowing capacity to $950 million while retaining the accordion feature that would allow an increase in borrowing capacity up to $1.2 billion and (ii) to permit same-day funding on base rate loans. We also terminated Atmos Energy Marketing's $200 million committed and secured credit facility and replaced this facility with two $25 million 364-day bilateral facilities, which should result in a decrease in external credit expense incurred in our nonregulated operations. After giving effect to these changes, we have over $1 billion of working capital funding from four committed revolving credit facilities and one noncommitted revolving credit facility.

On January 11, 2013, we issued $500 million of 4.15% 30-year unsecured senior notes, which replaced, on a long-term basis, our $250 million 5.125% 10-year unsecured senior notes we redeemed in August 2012. The net proceeds of approximately $494 million were used to repay $260 million outstanding under the short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes.

The following table presents our consolidated financial highlights for the three months ended December 31, 2012 and 2011:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands, except per share data) | |
| Operating revenues | $1,034,155 | $1,083,994 |
| Gross profit | 362,362 | 355,392 |
| Operating expenses | 207,440 | 215,921 |
| Operating income | 154,922 | 139,471 |
| Miscellaneous income (expense) | 698 | (2,016) |
| Interest charges | 30,522 | 35,726 |
| Income from continuing operations before income taxes | 125,098 | 101,729 |
| Income tax expense | 47,750 | 39,345 |
| Income from continuing operations | 77,348 | 62,384 |
| Income from discontinued operations, net of tax | 3,117 | 6,123 |
| Net income | $ 80,465 | $ 68,507 |
| Diluted net income per share from continuing operations | $ 0.85 | $ 0.68 |
| Diluted net income per share from discontinued operations | 0.03 | 0.07 |
| Diluted net income per share | $ 0.88 | $ 0.75 |

Our consolidated net income during the three months ended December 31, 2012 and 2011 was earned in each of our business segments as follows:

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Natural gas distribution segment | $56,210 | $50,624 | $ 5,586 |
| Regulated transmission and storage segment | 16,105 | 13,414 | 2,691 |
| Nonregulated segment | 8,150 | 4,469 | 3,681 |
| Net income | $80,465 | $68,507 | $11,958 |

The following table reflects our consolidated net income and diluted earnings per share in our regulated and nonregulated operations:

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $69,198 | $57,915 | $11,283 |
| Nonregulated operations | 8,150 | 4,469 | 3,681 |
| Net income from continuing operations | 77,348 | 62,384 | 14,964 |
| Net income from discontinued operations | 3,117 | 6,123 | (3,006) |
| Net income | $80,465 | $68,507 | $11,958 |
| Diluted EPS from continuing regulated operations | $ 0.76 | $ 0.63 | $ 0.13 |
| Diluted EPS from nonregulated operations | 0.09 | 0.05 | 0.04 |
| Diluted EPS from continuing operations | 0.85 | 0.68 | 0.17 |
| Diluted EPS from discontinued operations | 0.03 | 0.07 | (0.04) |
| Consolidated diluted EPS | $ 0.88 | $ 0.75 | $ 0.13 |

***Three Months Ended December 31, 2012 compared with Three Months Ended December 31, 2011***

***Natural Gas Distribution Segment***

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

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 96 percent of our residential and commercial meters in the following states for the following time periods:

| | |
|---|---|
| Georgia, Kansas, West Texas | October — May |
| Kentucky, Mississippi, Tennessee, Mid-Tex | November — April |
| Louisiana | December — March |
| Virginia | January — December |

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without a markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas does include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs mean higher bills for our customers, which may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 75 percent of our residential and commercial margins.

In August 2012, we announced that we had entered into a definitive agreement to sell substantially all of our natural gas distribution operations in Georgia. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The sale of these service areas was completed in August 2012. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

During the first quarter of fiscal 2013, we completed seven regulatory proceedings, which should result in a \$63.7 million increase in annual operating income. The majority of this rate increase related to our Mid-Tex Division, where rates became effective January 1, 2013. The rate design approved in our Mid-Tex Division and West Texas Division regulatory proceedings includes an increase in the base customer charge and a decrease in the commodity charged applied to customer consumption. The effect of this change in rate design allows the Company's rates to be more closely aligned with utility industry standard rate design. In addition, we anticipate these divisions will earn their operating income more ratably over the fiscal year as we are now less dependent on customer consumption. Therefore, we anticipate operating income earned during the first and second quarters to be lower than in previous periods while operating income earned during the third and fourth quarters to be higher than in previous periods. Accordingly, we anticipate our 2013 period-over-period results will reflect the impact of these rate design changes.

*Review of Financial and Operating Results*

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2012 and 2011 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $279,631 | $283,595 | $ (3,964) |
| Operating expenses | 170,547 | 180,170 | (9,623) |
| **Operating income** | 109,084 | 103,425 | 5,659 |
| Miscellaneous expense | (131) | (1,897) | 1,766 |
| Interest charges | 23,563 | 28,139 | (4,576) |
| **Income from continuing operations before income taxes** | 85,390 | 73,389 | 12,001 |
| Income tax expense | 32,297 | 28,888 | 3,409 |
| **Income from continuing operations** | 53,093 | 44,501 | 8,592 |
| Income from discontinued operations, net of tax | 3,117 | 6,123 | (3,006) |
| Net income | $ 56,210 | $ 50,624 | $ 5,586 |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 78,753 | 83,367 | (4,614) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 32,889 | 32,277 | 612 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 111,642 | 115,644 | (4,002) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 2,057 | 6,104 | (4,047) |
| Total consolidated natural gas distribution throughput — MMcf | 113,699 | 121,748 | (8,049) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.47 | $ 0.45 | $ 0.02 |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 4.93 | $ 4.78 | $ 0.15 |

The $4.0 million decrease in natural gas distribution gross profit primarily reflects the following:

- $4.6 million net decrease in rate adjustments, primarily in the Mid-Tex Division due to the rate design approved in our most recent Mid-Tex rate case, which includes an increase in the base customer charge and a decrease in the commodity charge applied to customer consumption.
- $2.7 million decrease in revenue related taxes in our Mid-Tex and West Texas Divisions, primarily due to lower revenues on which the tax is calculated.

These decreases were partially offset by a $2.4 million increase from colder weather, primarily in the Mid-Tex service area.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, decreased $9.6 million, primarily due to the following:

- $2.8 million decrease in legal costs, primarily due to the absence of prior-year settlement costs.
- $1.9 million decrease in franchise fees due to lower revenue on which the tax is calculated.
- $1.7 million decrease due to the establishment of regulatory assets for pension and postretirement costs.
- $1.0 million decrease in operating expenses due to increased capital spending.

Interest charges decreased $4.6 million, primarily from interest capitalized related to Rule 8.209 spending in the current quarter and the early redemption of the 5.125% $250 million senior notes due January 2013, with funds borrowed under a $260 million short-term debt facility in August 2012.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended December 31, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | | (In thousands) | |
| Mid-Tex | $ 45,577 | $ 48,449 | $(2,872) |
| Kentucky/Mid-States | 15,705 | 11,382 | 4,323 |
| Louisiana | 16,885 | 15,201 | 1,684 |
| West Texas | 9,578 | 10,675 | (1,097) |
| Mississippi | 11,613 | 10,132 | 1,481 |
| Colorado-Kansas | 8,744 | 8,179 | 565 |
| Other | 982 | (593) | 1,575 |
| Total | $109,084 | $103,425 | $ 5,659 |

*Recent Ratemaking Developments*

Significant ratemaking developments that occurred during the three months ended December 31, 2012 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a final order from a commission or other governmental authority.

Annual net operating income increases totaling $63.7 million resulting from ratemaking activity became effective in the quarter ended December 31, 2012 as summarized below:

| Rate Action | Annual Increase to Operating Income |
|---|---|
| | (In thousands) |
| Rate case filings | $56,700 |
| Infrastructure programs | 3,605 |
| Annual rate filing mechanisms | 3,441 |
| | $63,746 |

Additionally, the following ratemaking efforts were in progress during the first quarter of fiscal 2013 but had not been completed as of December 31, 2012.

| Division | Rate Action | Jurisdiction | Operating Income Requested |
|---|---|---|---|
| | | | (In thousands) |
| Colorado-Kansas | Ad Valorem[1] | Kansas | $1,322 |
| Colorado-Kansas | GSRS[2] | Kansas | 681 |
| Colorado-Kansas | Infrastructure Replacement | Colorado | 871 |
| Louisiana | Rate Stabilization Clause | TransLa | 2,730 |
| Kentucky/Mid-States | Georgia Rate Adjustment Mechanism[3] | Georgia | 1,079 |
| | | | $6,683 |

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates. The commission issued a final order on January 16, 2013 for an increase in operating income of $1.3 million.

(2) The Gas System Reliability Surcharge (GSRS) filing relates to a collection of qualified infrastructure in Kansas. The Commission issued a final order on January 9, 2013 for an increase in operating income of $0.6 million.

(3) On January 31, 2013, the Georgia commission approved a $0.7 million increase in operating revenues effective February 1, 2013.

*Rate Case Filings*

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return for our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service safely to our customers. The following table summarizes the rate cases that were completed during the three months ended December 31, 2012.

| Division | State | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|
| | | (In thousands) | |
| *2013 Rate Case Filings:* | | | |
| Mid-Tex | Texas | $42,601 | 12/04/2012 |
| Kentucky/Mid-States | Tennessee | 7,530 | 11/08/2012 |
| West Texas | Texas | 6,569 | 10/01/2012 |
| Total 2013 Rate Case Filings | | $56,700 | |

*Infrastructure Programs*

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow our regulated divisions the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates during the three months ended December 31, 2012.

| Division | Period End | Incremental Net Utility Plant Investment | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | (In thousands) | (In thousands) | |
| *2013 Infrastructure Programs:* | | | | |
| Kentucky/Mid-States — Georgia | 09/2011 | $ 6,519 | $1,079 | 10/01/2012 |
| Kentucky/Mid-States — Kentucky | 09/2013 | 19,296 | 2,425 | 10/01/2012 |
| Kentucky/Mid-States — Virginia | 09/2013 | 756 | 101 | 10/01/2012 |
| Total 2013 Infrastructure Programs | | $26,571 | $3,605 | |

*Annual Rate Filing Mechanism*

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana, Georgia and Mississippi service areas and in a portion of our Mid-Tex Division. These mechanisms are referred to as the Dallas annual rate review (DARR) in our Mid-Tex Division, stable rate filings in the Mississippi Division, Georgia rate adjustment mechanism in our Kentucky/Mid-States Division and a rate stabilization clause in the Louisiana Division. We expect to initiate discussions regarding a new rate review mechanism processes in our West Texas and Mid-Tex Divisions in fiscal 2013. The following annual rate filing mechanism was completed during the three months ended December 31, 2012.

| Division | Jurisdiction | Test Year Ended | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2013 Filings:* | | | | |
| Mississippi | Mississippi | 6/30/2012 | $3,441 | 11/1/2012 |
| Total 2013 Filings | | | $3,441 | |

*Other Ratemaking Activity*

There was no other ratemaking activity completed during the three months ended December 31, 2012.

***Regulated Transmission and Storage Segment***

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

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

The results of Atmos Pipeline–Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

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

*Review of Financial and Operating Results*

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2012 and 2011 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 40,785 | $ 37,343 | $3,442 |
| Third-party transportation | 14,549 | 14,939 | (390) |
| Storage and park and lend services | 1,510 | 1,806 | (296) |
| Other | 3,837 | 2,671 | 1,166 |
| **Gross profit** | 60,681 | 56,759 | 3,922 |
| Operating expenses | 28,659 | 28,400 | 259 |
| **Operating income** | 32,022 | 28,359 | 3,663 |
| Miscellaneous expense | (127) | (280) | 153 |
| Interest charges | 6,871 | 7,209 | (338) |
| **Income before income taxes** | 25,024 | 20,870 | 4,154 |
| Income tax expense | 8,919 | 7,456 | 1,463 |
| **Net income** | $ 16,105 | $ 13,414 | $2,691 |
| Gross pipeline transportation volumes — MMcf | 161,484 | 160,829 | 655 |
| Consolidated pipeline transportation volumes — MMcf | 108,743 | 105,037 | 3,706 |

The $3.9 million increase in regulated transmission and storage gross profit was primarily a result of the GRIP filing approved by the RRC during fiscal 2012. During the third fiscal quarter of fiscal 2012, the RRC approved the Atmos Pipeline–Texas GRIP filing with an annual operating income increase of $14.7 million that went into effect in April 2012.

The GRIP filing approved in fiscal 2012 increased quarter-over-quarter gross profit by $3.7 million. In addition, excess retention gas sales increased gross profit by $0.7 million. Partially offsetting these increases was a decrease of $0.6 million due to decreased priority reservation and demand fees.

***Nonregulated Segment***

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. These activities are reflected as gas delivery and related services in the table below.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. Most of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight. These activities are reflected as storage and transportation services in the table below.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas and demand fees paid to contract for storage capacity to offer more competitive pricing to those customers.

Further, natural gas market conditions, most notably the price of natural gas and the level of price volatility affect our nonregulated businesses. Natural gas prices and the level of volatility are influenced by a number of factors including, but not limited to, general economic conditions, the demand for natural gas in different parts of the country, the level of domestic natural gas production and the level of natural gas inventory levels.

Natural gas prices can influence:

- The demand for natural gas. Higher prices may cause customers to conserve or use alternative energy sources. Conversely, lower prices could cause customers such as electric power generators to switch from alternative energy sources to natural gas.
- Collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment.
- The level of borrowings under our credit facilities, which affects the level of interest expense recognized by this segment.

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Price volatility also influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads.
- Increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

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

*Review of Financial and Operating Results*

Financial and operational highlights for our nonregulated segment for the three months ended December 31, 2012 and 2011 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 10,070 | $ 11,113 | $(1,043) |
| Storage and transportation services | 3,521 | 3,189 | 332 |
| Other | 1,013 | 1,017 | (4) |
| | 14,604 | 15,319 | (715) |
| Asset optimization[1] | (15,123) | (21,594) | 6,471 |
| **Total realized margins** | (519) | (6,275) | 5,756 |
| **Unrealized margins** | 22,978 | 21,680 | 1,298 |
| **Gross profit** | 22,459 | 15,405 | 7,054 |
| Operating expenses | 8,645 | 7,719 | 926 |
| **Operating income** | 13,814 | 7,686 | 6,128 |
| Miscellaneous income | 1,667 | 36 | 1,631 |
| Interest charges | 797 | 252 | 545 |
| **Income before income taxes** | 14,684 | 7,470 | 7,214 |
| Income tax expense | 6,534 | 3,001 | 3,533 |
| **Net income** | $ 8,150 | $ 4,469 | $ 3,681 |
| Gross nonregulated delivered gas sales volumes — MMcf | 99,009 | 106,462 | (7,453) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 84,718 | 90,870 | (6,152) |
| Net physical position (Bcf) | 25.8 | 35.6 | (9.8) |

(1) Net of storage fees of $5.9 million and $4.7 million.

Results for our nonregulated operations during the first fiscal quarter were adversely influenced by continued unfavorable natural gas market conditions. Historically high natural gas storage levels primarily resulting from strong domestic natural gas production caused natural gas prices to remain relatively low during the first fiscal quarter. Further, unseasonably warm weather reduced the demand for natural gas.

We anticipate these natural gas market conditions will continue for the foreseeable future. As a result, we anticipate that basis differentials will remain compressed and spot-to-forward price volatility will remain relatively low. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be more consistent with the reduced margins we realized in fiscal 2012 than in previous years.

Realized margins for gas delivery, storage and transportation services and other services were $14.6 million during the three months ended December 31, 2012 compared with $15.3 million for the prior-year quarter. The decrease primarily reflects a seven percent decrease in consolidated sales volumes, which was largely attributable to warmer weather. Gas delivery per-unit margins remained consistent with prior-year per-unit margins at $0.10/Mcf.

Asset optimization margins increased \$6.5 million from the prior-year quarter, primarily due to smaller losses incurred from the settlement of financial positions, partially offset by higher storage demand fees.

Realized asset optimization margins for the prior-year quarter also included a \$1.7 million charge to write down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Operating expenses increased \$0.9 million, primarily due to higher contract labor costs.

Miscellaneous income increased \$1.6 million primarily due to a gain realized from the sale of a distributed electric generation plant and related assets.

### Liquidity and Capital Resources

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. As discussed below, we currently have over \$1 billion of capacity from our short-term facilities.

On January 11, 2013, we issued \$500 million of 4.15% 30-year unsecured senior notes, which, in effect, replaced our \$250 million 5.125% 30-year unsecured senior notes we redeemed in August 2012, on a long-term basis. The net proceeds of approximately \$494 million were used to repay \$260 million outstanding under our short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes, as discussed in Note 6.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2013.

### Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the three months ended December 31, 2012 and 2011 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2012 | 2011 | 2012 vs. 2011 |
| | | (In thousands) | |
| Total cash provided by (used in) | | | |
| Operating activities | \$ 29,858 | \$ (15,291) | \$ 45,149 |
| Investing activities | (191,300) | (155,474) | (35,826) |
| Financing activities | 221,804 | 124,506 | 97,298 |
| Change in cash and cash equivalents | 60,362 | (46,259) | 106,621 |
| Cash and cash equivalents at beginning of period | 64,239 | 131,419 | (67,180) |
| Cash and cash equivalents at end of period | \$ 124,601 | \$ 85,160 | \$ 39,441 |

*Cash flows from operating activities*

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

The $45.1 million increase in operating cash flows primarily reflects the timing of customer collections and vendor payments as well as the effect of a decrease in the amount of cash used to inject gas into storage, primarily in the company's nonregulated segment.

*Cash flows from investing activities*

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

Capital expenditures for fiscal 2013 are expected to range from $770 million to $790 million. For the three months ended December 31, 2012, capital expenditures were $190.0 million compared with $154.4 million for the three months ended December 31, 2011. The $35.6 million increase in capital expenditures primarily reflects infrastructure spending incurred under RRC Rule 8.209 in the Mid-Tex Division of our natural gas distribution segment and for the Line W and Line WX pipeline expansion projects in our regulated transmission and storage segment.

*Cash flows from financing activities*

The $97.3 million increase in financing cash flows was primarily due to the following:

- $83.0 million additional cash provided from short-term debt borrowings.
- $12.5 million increase in cash flows due to the absence of prior-year common stock repurchases as part of our share repurchase program.
- $2.3 million increase in cash flows due to lower repayments of long-term debt. In the current-year quarter, we did not repay any long-term debt compared to $2.3 million repaid in the prior-year quarter.

The following table summarizes our share issuances for the three months ended December 31, 2012 and 2011.

| | Three Months Ended December 31 | |
|---|---|---|
| | **2012** | **2011** |
| Shares issued: | | |
| 1998 Long-Term Incentive Plan | 364,415 | 197,503 |
| Outside Directors Stock-for-Fee Plan | 564 | 618 |
| Total shares issued | 364,979 | 198,121 |

The quarter-over-quarter increase in the number of shares issued primarily reflects the type of awards that were issued from the 1998 Long-Term Incentive Plan in each period. In the current-year period, employees were issued restricted stock units, for which we issued new shares. In the prior-year period, employees were issued restricted stock awards, which were held in trust and did not require the issuance of new shares. For the three months ended December 31, 2012 and 2011, we cancelled and retired 87,931 and 99,555 shares attributable to federal withholdings on equity awards. For the three months ended December 31, 2011, we repurchased and retired 387,991 shares through our 2011 share repurchase program.

### Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.0 billion of working capital funding. As of December 31, 2012, the amount available to us under our credit facilities, net of outstanding letters of credit, was $446.6 million.

### Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At December 31, 2012, $900 million remained available for issuance under the shelf until it expires on March 31, 2013. However, with the issuance of $500 million of long-term debt on January 11, 2013, as described in Note 6, our remaining availability has been reduced to $400 million. We intend to file a new shelf registration statement with the SEC for $1.75 billion prior to the expiration of the current shelf registration statement.

### Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of December 31, 2012, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Unsecured senior long-term debt | BBB+ | Baa1 | A- |
| Commercial paper | A-2 | P-2 | F-2 |

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating 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 independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

## Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2012. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

## Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2012, September 30, 2012 and December 31, 2011:

| | December 31, 2012 | | September 30, 2012 | | December 31, 2011 | |
|---|---|---|---|---|---|---|
| | (In thousands, except percentages) | | | | | |
| Short-term debt[1] | $ 830,891 | 15.9% | $ 570,929 | 11.7% | $ 389,985 | 8.0% |
| Long-term debt | 1,956,507 | 37.6% | 1,956,436 | 40.0% | 2,206,324 | 45.4% |
| Shareholders' equity | 2,424,005 | 46.5% | 2,359,243 | 48.3% | 2,267,762 | 46.6% |
| Total | $5,211,403 | 100.0% | $4,886,608 | 100.0% | $4,864,071 | 100.0% |

[1] Short-term debt at December 31, 2012 and September 30, 2012 included $260 million outstanding related to a short-term facility we used to redeem our $250 million 5.125% Senior notes in August 2012. The balance outstanding under this short-term facility was repaid in January 2013.

Total debt as a percentage of total capitalization, including short-term debt, was 53.5 percent at December 31, 2012, 51.7 percent at September 30, 2012 and 53.4 percent at December 31, 2011. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

## Contractual Obligations and Commercial Commitments

Our significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2012.

## Risk Management Activities

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2012 and 2011:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Fair value of contracts at beginning of period | $(76,260) | $(79,277) |
| Contracts realized/settled | 2,834 | (17,729) |
| Fair value of new contracts | 331 | (555) |
| Other changes in value | 8,898 | 11,732 |
| Fair value of contracts at end of period | $(64,197) | $(85,829) |

The fair value of our natural gas distribution segment's financial instruments at December 31, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(75,807) | $11,610 | $— | $— | $(64,197) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(75,807) | $11,610 | $— | $— | $(64,197) |

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three months ended December 31, 2012 and 2011:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Fair value of contracts at beginning of period | $(15,123) | $(25,050) |
| Contracts realized/settled | 12,736 | 17,449 |
| Fair value of new contracts | — | — |
| Other changes in value | 825 | (7,662) |
| Fair value of contracts at end of period | (1,562) | (15,263) |
| Netting of cash collateral | 16,559 | 22,084 |
| Cash collateral and fair value of contracts at period end | $ 14,997 | $ 6,821 |

The fair value of our nonregulated segment's financial instruments at December 31, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $1,298 | $(2,842) | $ (5) | $(13) | $(1,562) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $1,298 | $(2,842) | $ (5) | $(13) | $(1,562) |

**Pension and Postretirement Benefits Obligations**

For the three months ended December 31, 2012 and 2011, our total net periodic pension and other benefits cost was $18.9 million and $17.3 million. Those costs relating to our natural gas distribution operations are generally recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2013 costs were determined using a September 30, 2012 measurement date. As of September 30, 2012, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2011, the measurement date for our fiscal 2012 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2013 pension and benefit costs to

4.04 percent. The expected return on our pension plan assets remained at 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2013 pension and postretirement medical costs for the quarter ended December 31, 2012 were higher than the prior-year quarter.

The amounts with which we fund our defined benefit plans are determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plans when the funding requirements are determined on January 1 of each year. Based upon the most recent evaluation, we anticipate contributing a total of between $30 million and $40 million to our defined benefit plans in fiscal 2013. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing a total of between $25 million and $30 million to these plans during fiscal 2013.

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

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three-month periods ended December 31, 2012 and 2011.

*Natural Gas Distribution Sales and Statistical Data — Continuing Operations*

| | Three Months Ended December 31 | |
|---|---|---|
| | 2012 | 2011 |
| **METERS IN SERVICE, end of period** | | |
| Residential | 2,805,013 | 2,788,455 |
| Commercial | 256,030 | 253,846 |
| Industrial | 2,127 | 2,236 |
| Public authority and other | 10,169 | 10,215 |
| Total meters | 3,073,339 | 3,054,752 |
| **INVENTORY STORAGE BALANCE — Bcf**[1] | 54.8 | 58.1 |
| **SALES VOLUMES — MMcf**[2] | | |
| Gas sales volumes | | |
| Residential | 46,323 | 49,469 |
| Commercial | 25,256 | 26,223 |
| Industrial | 4,555 | 5,057 |
| Public authority and other | 2,619 | 2,618 |
| Total gas sales volumes | 78,753 | 83,367 |
| Transportation volumes | 34,022 | 33,412 |
| Total throughput | 112,775 | 116,779 |
| **OPERATING REVENUES (000's)**[2] | | |
| Gas sales revenues | | |
| Residential | $ 422,721 | $ 427,310 |
| Commercial | 184,931 | 186,079 |
| Industrial | 21,456 | 24,229 |
| Public authority and other | 15,680 | 17,373 |
| Total gas sales revenues | 644,788 | 654,991 |
| Transportation revenues | 15,441 | 14,292 |
| Other gas revenues | 6,558 | 6,830 |
| Total operating revenues | $ 666,787 | $ 676,113 |
| Average transportation revenue per Mcf[1] | $ 0.46 | $ 0.44 |
| Average cost of gas per Mcf sold[1] | $ 4.93 | $ 4.78 |

See footnote following these tables.

*Natural Gas Distribution Sales and Statistical Data — Discontinued Operations*

| | Three Months Ended December 31 | |
|---|---|---|
| | **2012** | **2011** |
| Meters in service, end of period | 63,959 | 148,256 |
| Sales volumes — MMcf | | |
| Total gas sales volumes | 1,542 | 3,952 |
| Transportation volumes | 515 | 2,152 |
| Total throughput | 2,057 | 6,104 |
| Operating revenues (000's) | $16,284 | $ 40,630 |

*Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data*

| | Three Months Ended December 31 | |
|---|---|---|
| | **2012** | **2011** |
| **CUSTOMERS, end of period** | | |
| Industrial | 732 | 771 |
| Municipal | 128 | 69 |
| Other | 423 | 516 |
| Total | 1,283 | 1,356 |
| **NONREGULATED INVENTORY STORAGE BALANCE — Bcf** | 26.9 | 27.9 |
| **REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf** (2) | 161,484 | 160,829 |
| **NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf**(2) | 99,009 | 106,462 |
| **OPERATING REVENUES (000's)** (2) | | |
| Regulated transmission and storage | $ 60,681 | $ 56,759 |
| Nonregulated | 399,894 | 444,176 |
| Total operating revenues | $460,575 | $500,935 |

Note to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

## RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. During the three months ended December 31, 2012, there were no material changes in our quantitative and qualitative disclosures about market risk.

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

**Management's Evaluation of Disclosure Controls and Procedures**

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

**Changes in Internal Control over Financial Reporting**

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

**Item 1.** ***Legal Proceedings***

During the three months ended December 31, 2012, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

**Item 6.** ***Exhibits***

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

**SIGNATURE**

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ BRET J. ECKERT

Bret J. Eckert
*Senior Vice President and Chief Financial Officer*
(Duly authorized signatory)

Date: February 7, 2013

## EXHIBITS INDEX
### Item 6

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 12 | Computation of ratio of earnings to fixed charges | |
| 15 | Letter regarding unaudited interim financial information | |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications* | |
| 101.INS | XBRL Instance Document | |
| 101.SCH | XBRL Taxonomy Extension Schema | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase | |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase | |

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

# 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, 2012**

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of August 3, 2012.

| Class | Shares Outstanding |
|---|---|
| No Par Value | 90,173,217 |

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AOCI | Accumulated other comprehensive income |
| APS | Atmos Pipeline and Storage, LLC |
| Bcf | Billion cubic feet |
| CFTC | Commodity Futures Trading Commission |
| FASB | Financial Accounting Standards Board |
| Fitch | Fitch Ratings, Ltd. |
| GRIP | Gas Reliability Infrastructure Program |
| GSRS | Gas System Reliability Surcharge |
| ISRS | Infrastructure System Replacement Surcharge |
| Mcf | Thousand cubic feet |
| MMcf | Million cubic feet |
| Moody's | Moody's Investors Services, Inc. |
| NYMEX | New York Mercantile Exchange, Inc. |
| PPA | Pension Protection Act of 2006 |
| PRP | Pipeline Replacement Program |
| RRC | Railroad Commission of Texas |
| RRM | Rate Review Mechanism |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| WNA | Weather Normalization Adjustment |

## PART I. FINANCIAL INFORMATION

**Item 1.** ***Financial Statements***

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED BALANCE SHEETS

| | June 30, 2012 | September 30, 2011 |
|---|---|---|
| | (Unaudited) | |
| | (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $7,128,484 | $6,816,794 |
| Less accumulated depreciation and amortization | 1,686,598 | 1,668,876 |
| Net property, plant and equipment | 5,441,886 | 5,147,918 |
| Current assets | | |
| Cash and cash equivalents | 27,706 | 131,419 |
| Accounts receivable, net | 216,753 | 273,303 |
| Gas stored underground | 239,329 | 289,760 |
| Other current assets | 291,870 | 316,471 |
| Total current assets | 775,658 | 1,010,953 |
| Goodwill and intangible assets | 740,174 | 740,207 |
| Deferred charges and other assets | 392,117 | 383,793 |
| | $7,349,835 | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2012 — 90,172,665 shares; September 30, 2011 — 90,296,482 shares | $ 451 | $ 451 |
| Additional paid-in capital | 1,737,047 | 1,732,935 |
| Retained earnings | 684,907 | 570,495 |
| Accumulated other comprehensive loss | (67,480) | (48,460) |
| Shareholders' equity | 2,354,925 | 2,255,421 |
| Long-term debt | 1,956,289 | 2,206,117 |
| Total capitalization | 4,311,214 | 4,461,538 |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 178,198 | 291,205 |
| Other current liabilities | 468,409 | 367,563 |
| Short-term debt | 213,491 | 206,396 |
| Current maturities of long-term debt | 250,131 | 2,434 |
| Total current liabilities | 1,110,229 | 867,598 |
| Deferred income taxes | 1,085,654 | 960,093 |
| Regulatory cost of removal obligation | 381,797 | 428,947 |
| Deferred credits and other liabilities | 460,941 | 564,695 |
| | $7,349,835 | $7,282,871 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Three Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $325,051 | $ 407,031 |
| Regulated transmission and storage segment | 67,073 | 53,570 |
| Nonregulated segment | 256,250 | 491,285 |
| Intersegment eliminations | (62,543) | (108,271) |
| | 585,831 | 843,615 |
| Purchased gas cost | | |
| Natural gas distribution segment | 124,373 | 206,839 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 224,829 | 477,880 |
| Intersegment eliminations | (62,161) | (107,909) |
| | 287,041 | 576,810 |
| Gross profit | 298,790 | 266,805 |
| Operating expenses | | |
| Operation and maintenance | 107,295 | 112,665 |
| Depreciation and amortization | 59,819 | 56,932 |
| Taxes, other than income | 46,887 | 52,142 |
| Asset impairments | — | 10,988 |
| Total operating expenses | 214,001 | 232,727 |
| Operating income | 84,789 | 34,078 |
| Miscellaneous expense | (1,948) | (1,430) |
| Interest charges | 34,923 | 35,845 |
| Income (loss) from continuing operations before income taxes | 47,918 | (3,197) |
| Income tax expense (benefit) | 17,774 | (1,723) |
| Income (loss) from continuing operations | 30,144 | (1,474) |
| Income from discontinued operations, net of tax ($566 and $590) | 988 | 908 |
| Net income (loss) | $ 31,132 | $ (566) |
| Basic earnings per share | | |
| Income (loss) per share from continuing operations | $ 0.33 | $ (0.02) |
| Income per share from discontinued operations | 0.01 | 0.01 |
| Net income (loss) per share — basic | $ 0.34 | $ (0.01) |
| Diluted earnings per share | | |
| Income (loss) per share from continuing operations | $ 0.33 | $ (0.02) |
| Income per share from discontinued operations | 0.01 | 0.01 |
| Net income (loss) per share — diluted | $ 0.34 | $ (0.01) |
| Cash dividends per share | $ 0.345 | $ 0.340 |
| Weighted average shares outstanding: | | |
| Basic | 90,118 | 90,127 |
| Diluted | 90,993 | 90,127 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $1,907,351 | $2,187,907 |
| Regulated transmission and storage segment | 181,869 | 157,553 |
| Nonregulated segment | 1,071,189 | 1,550,456 |
| Intersegment eliminations | (229,955) | (337,542) |
| | 2,930,454 | 3,558,374 |
| Purchased gas cost | | |
| Natural gas distribution segment | 1,034,786 | 1,317,775 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 1,028,592 | 1,491,815 |
| Intersegment eliminations | (228,857) | (336,413) |
| | 1,834,521 | 2,473,177 |
| Gross profit | 1,095,933 | 1,085,197 |
| Operating expenses | | |
| Operation and maintenance | 334,065 | 341,317 |
| Depreciation and amortization | 179,306 | 167,176 |
| Taxes, other than income | 145,004 | 145,868 |
| Asset impairments | — | 30,270 |
| Total operating expenses | 658,375 | 684,631 |
| Operating income | 437,558 | 400,566 |
| Miscellaneous income (expense) | (3,207) | 24,046 |
| Interest charges | 107,025 | 112,615 |
| Income from continuing operations before income taxes | 327,326 | 311,997 |
| Income tax expense | 125,484 | 114,211 |
| Income from continuing operations | 201,842 | 197,786 |
| Income from discontinued operations, net of tax ($3,959 and $5,122) | 6,908 | 7,854 |
| Net income | $ 208,750 | $ 205,640 |
| Basic earnings per share | | |
| Income per share from continuing operations | $ 2.23 | $ 2.17 |
| Income per share from discontinued operations | 0.08 | 0.09 |
| Net income per share — basic | $ 2.31 | $ 2.26 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 2.21 | $ 2.16 |
| Income per share from discontinued operations | 0.07 | 0.09 |
| Net income per share — diluted | $ 2.28 | $ 2.25 |
| Cash dividends per share | $ 1.035 | $ 1.020 |
| Weighted average shares outstanding: | | |
| Basic | 90,131 | 90,233 |
| Diluted | 91,006 | 90,530 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands) | |
| Cash Flows From Operating Activities | | |
| Net income | $ 208,750 | $ 205,640 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Asset impairments | — | 30,270 |
| Depreciation and amortization: | | |
| Charged to depreciation and amortization | 183,884 | 171,726 |
| Charged to other accounts | 310 | 149 |
| Deferred income taxes | 120,713 | 115,488 |
| Other | 22,386 | 15,927 |
| Net assets / liabilities from risk management activities | 12,759 | (15,869) |
| Net change in operating assets and liabilities | (29,996) | (3,769) |
| Net cash provided by operating activities | 518,806 | 519,562 |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (497,374) | (390,283) |
| Other, net | (4,247) | (3,373) |
| Net cash used in investing activities | (501,621) | (393,656) |
| Cash Flows From Financing Activities | | |
| Net decrease in short-term debt | (6,688) | (132,072) |
| Net proceeds from issuance of long-term debt | — | 394,618 |
| Settlement of Treasury lock agreements | — | 20,079 |
| Unwinding of Treasury lock agreements | — | 27,803 |
| Repayment of long-term debt | (2,369) | (360,066) |
| Cash dividends paid | (94,338) | (93,039) |
| Repurchase of common stock | (12,535) | — |
| Repurchase of equity awards | (5,219) | (5,300) |
| Issuance of common stock | 251 | 7,548 |
| Net cash used in financing activities | (120,898) | (140,429) |
| Net decrease in cash and cash equivalents | (103,713) | (14,523) |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 |
| Cash and cash equivalents at end of period | $ 27,706 | $ 117,429 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) June 30, 2012

### 1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which at June 30, 2012 covered service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. On August 1, 2012, we completed the divestiture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. On August 8, 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and headquartered in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

We operate the Company through the following three segments:

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

### 2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2012 are not indicative of our results of operations for the full 2012 fiscal year, which ends September 30, 2012.

We have evaluated subsequent events from the June 30, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). On July 27, 2012, we issued a notice of redemption of our Unsecured 5.125% Senior Notes on August 28, 2012. The redemption is discussed further in Note 6. On August 1, 2012, we completed the sale of our Missouri, Illinois and Iowa natural gas distribution assets. The sale is discussed in Note 5. On August 8, 2012 we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, which is discussed in Note 5.

***Significant accounting policies***

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011.

During the second quarter of fiscal 2012, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the nine months ended June 30, 2012, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard indefinitely defers the effective date for new presentation requirements related to reclassifications of items from accumulated other comprehensive income, which were scheduled to be effective for interim and annual periods beginning after December 15, 2011. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the nine months ended June 30, 2012.

***Regulatory assets and liabilities***

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2012 and September 30, 2011 included the following:

| | June 30, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| **Regulatory assets:** | | |
| Pension and postretirement benefit costs | $240,312 | $254,666 |
| Merger and integration costs, net | 5,876 | 6,242 |
| Deferred gas costs | 14,495 | 33,976 |
| Regulatory cost of removal asset | 10,430 | 8,852 |
| Environmental costs | 52 | 385 |
| Rate case costs | 4,454 | 4,862 |
| Deferred franchise fees | 2,129 | 379 |
| Other | 13,236 | 3,534 |
| | $290,984 | $312,896 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 34,044 | $ 8,130 |
| Regulatory cost of removal obligation | 449,778 | 464,025 |
| Other | 6,465 | 14,025 |
| | $490,287 | $486,180 |

The amounts above do not include regulatory assets and liabilities related to our divested Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as of June 30, 2012 as discussed in Note 5.

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of June 30, 2012, we had deferred $2.1 million associated with the requirements of this rule which are recorded in "Other" in the regulatory assets table above.

Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. We elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $5.1 million, which is recorded in "Other" in the regulatory assets table above. Of this amount, $2.9 million represented a reduction to operation and maintenance expense during the second and third quarters of fiscal 2012.

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

### *Comprehensive income*

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and nine-month periods ended June 30, 2012 and 2011:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Net income (loss) | $ 31,132 | $ (566) | $208,750 | $205,640 |
| Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(523) and $(56) for the three months ended June 30, 2012 and 2011 and of $1,194 and $876 for the nine months ended June 30, 2012 and 2011 | (888) | (94) | 2,059 | 1,492 |
| Amortization, unrealized gain (loss) and unwinding of treasury lock agreements, net of tax expense (benefit) of $(18,399) and $(4,629) for the three months ended June 30, 2012 and 2011 and $(9,995) and $7,950 for the nine months ended June 30, 2012 and 2011 | (31,328) | (7,884) | (17,019) | 13,536 |
| Net unrealized gains (losses) on cash flow hedging transactions, net of tax expense (benefit) of $11,401 and $(182) for the three months ended June 30, 2012 and 2011 and $(2,595) and $9,008 for the nine months ended June 30, 2012 and 2011 | 17,830 | (285) | (4,060) | 14,090 |
| Comprehensive income (loss) | $ 16,746 | $(8,829) | $189,730 | $234,758 |

Accumulated other comprehensive income (loss), net of tax, as of June 30, 2012 and September 30, 2011 consisted of the following unrealized gains (losses):

| | June 30, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive income (loss): | | |
| Unrealized holding gains on investments | $ 4,617 | $ 2,558 |
| Treasury lock agreements | (51,176) | (34,157) |
| Cash flow hedges | (20,921) | (16,861) |
| | $(67,480) | $(48,460) |

## 3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the nine months ended June 30, 2012 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

***Regulated Commodity Risk Management Activities***

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

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

***Nonregulated Commodity Risk Management Activities***

The primary business in our nonregulated operations is to aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. We utilize proprietary and customer-owned transportation and storage assets to serve these customers, and will seek to maximize the value of this storage capacity through the arbitrage of pricing differences that occur over time by selling financial instruments at advantageous prices to lock in a gross profit margin to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 53 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

### *Interest Rate Risk Management Activities*

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

As of June 30, 2012, we had three Treasury lock agreements outstanding to fix the Treasury yield component of 30-year unsecured notes, which we plan to issue in January 2013.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

### *Quantitative Disclosures Related to Financial Instruments*

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

As of June 30, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

| Contract Type | Hedge Designation | Natural Gas Distribution | Nonregulated |
|---|---|---|---|
| | | Quantity (MMcf) | |
| Commodity contracts | Fair Value | — | (33,110) |
| | Cash Flow | — | 42,625 |
| | Not designated | 15,940 | 38,773 |
| | | 15,940 | 48,288 |

*Financial Instruments on the Balance Sheet*

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2012 and September 30, 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $5.7 million and $28.8 million of cash held on deposit in margin accounts as of June 30, 2012 and September 30, 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **June 30, 2012** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 41,920 | $ 41,920 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | — | — |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (96,047) | (33,707) | (129,754) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (7,638) | (7,638) |
| **Total** | | (96,047) | 575 | (95,472) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 3,486 | 87,961 | 91,447 |
| Noncurrent commodity contracts | Deferred charges and other assets | 1,207 | 73,841 | 75,048 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[(1)] | (1,505) | (102,577) | (104,082) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (64,360) | (64,360) |
| **Total** | | 3,188 | (5,135) | (1,947) |
| **Total Financial Instruments** | | $(92,859) | $ (4,560) | $ (97,419) |

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.7 million related to risk management liabilities that were classified as assets held for sale at June 30, 2012.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **September 30, 2011** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts . . . | Other current assets | $ — | $ 22,396 | $ 22,396 |
| Noncurrent commodity contracts . . . . . . . . . . . . . . . . | Deferred charges and other assets | — | 174 | 174 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts . . . | Other current liabilities | — | (31,064) | (31,064) |
| Noncurrent commodity contracts . . . . . . . . . . . . . . . . | Deferred credits and other liabilities | (67,527) | (7,709) | (75,236) |
| **Total** . . . . . . . . . . . . . . . . . . . . . . . | | (67,527) | (16,203) | (83,730) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts . . . | Other current assets | 843 | 67,710 | 68,553 |
| Noncurrent commodity contracts . . . . . . . . . . . . . . . . | Deferred charges and other assets | 998 | 22,379 | 23,377 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts . . . | Other current liabilities[(1)] | (13,256) | (73,865) | (87,121) |
| Noncurrent commodity contracts . . . . . . . . . . . . . . . . | Deferred credits and other liabilities | (335) | (25,071) | (25,406) |
| **Total** . . . . . . . . . . . . . . . . . . . . . . . | | (11,750) | (8,847) | (20,597) |
| **Total Financial Instruments** . . . . . . | | $(79,277) | $(25,050) | $(104,327) |

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

*Impact of Financial Instruments on the Income Statement*

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2012 and 2011 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $19.0 million and $5.8 million. For the nine months ended June 30, 2012 and 2011 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $21.2 million and $23.3 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

*Fair Value Hedges*

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2012 and 2011 is presented below.

| | Three Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Commodity contracts | $(14,942) | $ 7,837 |
| Fair value adjustment for natural gas inventory designated as the hedged item | 34,296 | (1,781) |
| Total impact on revenue | $ 19,354 | $ 6,056 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 2,077 | $ 853 |
| Timing ineffectiveness | 17,277 | 5,203 |
| | $ 19,354 | $ 6,056 |

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Commodity contracts | $ 38,211 | $ 4,834 |
| Fair value adjustment for natural gas inventory designated as the hedged item | (16,039) | 19,430 |
| Total impact on revenue | $ 22,172 | $24,264 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 2,179 | $ 1,265 |
| Timing ineffectiveness | 19,993 | 22,999 |
| | $ 22,172 | $24,264 |

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the nine months ended June 30, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the nine months ended June 30, 2011.

*Cash Flow Hedges*

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2012 and 2011 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | Three Months Ended June 30, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI for effective portion of commodity contracts | $ — | $ — | $(19,534) | $(19,534) |
| Loss arising from ineffective portion of commodity contracts | — | — | (328) | (328) |
| Total impact on gross profit | — | — | (19,862) | (19,862) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (502) | — | — | (502) |
| Total Impact from Cash Flow Hedges | $(502) | $ — | $(19,862) | $(20,364) |

| | Three Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI for effective portion of commodity contracts | $ — | $ — | $(3,907) | $(3,907) |
| Loss arising from ineffective portion of commodity contracts | — | — | (281) | (281) |
| Total impact on gross profit | — | — | (4,188) | (4,188) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (614) | — | — | (614) |
| Total Impact from Cash Flow Hedges | $(614) | $ — | $(4,188) | $(4,802) |

| | Nine Months Ended June 30, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI for effective portion of commodity contracts | $ — | $ — | $(52,358) | $(52,358) |
| Loss arising from ineffective portion of commodity contracts | — | — | (996) | (996) |
| Total impact on gross profit | — | — | (53,354) | (53,354) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (1,506) | — | — | (1,506) |
| Total Impact from Cash Flow Hedges | $(1,506) | $ — | $(53,354) | $(54,860) |

| | Nine Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI for effective portion of commodity contracts | $ — | $ — | $(25,488) | $(25,488) |
| Loss arising from ineffective portion of commodity contracts | — | — | (958) | (958) |
| Total impact on gross profit | — | — | (26,446) | (26,446) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (1,953) | — | — | (1,953) |
| Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income | 21,803 | 6,000 | — | 27,803 |
| Total Impact from Cash Flow Hedges | $19,850 | $6,000 | $(26,446) | $ (596) |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| *Increase (decrease) in fair value:* | | | | |
| Treasury lock agreements | $(31,644) | $(8,270) | $(17,968) | $ 29,822 |
| Forward commodity contracts | 5,914 | (2,668) | (35,998) | (1,457) |
| *Recognition of (gains) losses in earnings due to settlements:* | | | | |
| Treasury lock agreements | 316 | 386 | 949 | (16,286) |
| Forward commodity contracts | 11,916 | 2,383 | 31,938 | 15,547 |
| Total other comprehensive income (loss) from hedging, net of tax[1] | $(13,498) | $(8,169) | $(21,079) | $ 27,626 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our treasury lock agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2012. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock agreements as these instruments have not yet settled.

| | Treasury Lock Agreements | Commodity Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| Next twelve months | $ (1,266) | $(16,543) | $(17,809) |
| Thereafter | 10,600 | (4,378) | 6,222 |
| Total[1] | $ 9,334 | $(20,921) | $(11,587) |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

*Financial Instruments Not Designated as Hedges*

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended June 30, 2012 and 2011 was an increase (decrease) in gross profit of $11.2 million and $(4.3) million. For the nine months ended June 30, 2012 and 2011 gross profit increased (decreased) $(3.8) million and $3.9 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

## 4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three and nine months ended June 30, 2012, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2011.

## Quantitative Disclosures

*Financial Instruments*

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2012 and September 30, 2011. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[2] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[3] | June 30, 2012 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 4,693 | $ — | $ — | $ 4,693 |
| Nonregulated segment[1] | 1,957 | 201,766 | — | (193,759) | 9,964 |
| Total financial instruments | 1,957 | 206,459 | — | (193,759) | 14,657 |
| Hedged portion of gas stored underground | 89,257 | — | — | — | 89,257 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 2,629 | — | — | 2,629 |
| Registered investment companies | 36,839 | — | — | — | 36,839 |
| Bonds | — | 23,421 | — | — | 23,421 |
| Total available-for-sale securities | 36,839 | 26,050 | — | — | 62,889 |
| Total assets | $128,053 | $232,509 | $ — | $(193,759) | $166,803 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 97,552 | $ — | $ — | $ 97,552 |
| Nonregulated segment[1] | 7,441 | 200,842 | — | (199,443) | 8,840 |
| Total liabilities | $ 7,441 | $298,394 | $ — | $(199,443) | $106,392 |

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[2] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[4] | September 30, 2011 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 1,841 | $ — | $ — | $ 1,841 |
| Nonregulated segment[1] | 8,502 | 104,156 | — | (95,156) | 17,502 |
| Total financial instruments | 8,502 | 105,997 | — | (95,156) | 19,343 |
| Hedged portion of gas stored underground | 47,940 | — | — | — | 47,940 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 1,823 | — | — | 1,823 |
| Registered investment companies | 36,444 | — | — | — | 36,444 |
| Bonds | — | 14,366 | — | — | 14,366 |
| Total available-for-sale securities | 36,444 | 16,189 | — | — | 52,633 |
| Total assets | $92,886 | $122,186 | $ — | $ (95,156) | $119,916 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 81,118 | $ — | $ — | $ 81,118 |
| Nonregulated segment[1] | 9,324 | 128,384 | — | (123,943) | 13,765 |
| Total liabilities | $ 9,324 | $209,502 | $ — | $(123,943) | $ 94,883 |

(1) Certain of the nonregulated segment's financial instruments were reclassified from Level 1 to Level 2 upon further evaluation.

(2) Our Level 2 measurements consist of over-the-counter options and swaps which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of June 30, 2012, we had $5.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $1.8 million was used to offset current risk management liabilities under master netting arrangements and the remaining $3.9 million is classified as current risk management assets.

(4) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

| | Amortized Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| | | (In thousands) | | |
| **As of June 30, 2012:** | | | | |
| Domestic equity mutual funds | $24,322 | $6,887 | $ — | $31,209 |
| Foreign equity mutual funds | 5,328 | 342 | (40) | 5,630 |
| Bonds | 23,282 | 145 | (6) | 23,421 |
| Money market funds | 2,629 | — | — | 2,629 |
| | $55,561 | $7,374 | $ (46) | $62,889 |
| **As of September 30, 2011:** | | | | |
| Domestic equity mutual funds | $27,748 | $4,074 | $ — | $31,822 |
| Foreign equity mutual funds | 4,597 | 267 | (242) | 4,622 |
| Bonds | 14,390 | 10 | (34) | 14,366 |
| Money market funds | 1,823 | — | — | 1,823 |
| | $48,558 | $4,351 | $(276) | $52,633 |

At June 30, 2012 and September 30, 2011, our available-for-sale securities included $39.5 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2012 we maintained investments in bonds that have contractual maturity dates ranging from July 2012 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.7 million in an unrealized loss position of less than $0.1 million as of June 30, 2012. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary as of June 30, 2012.

We also maintained several bonds with a cumulative fair value of $3.8 million in an unrealized loss position of less than $0.1 million as of June 30, 2012. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment grade, we do not consider this impairment to be other than temporary as of June 30, 2012.

*Other Fair Value Measures*

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of June 30, 2012:

| | June 30, 2012 |
|---|---|
| | (In thousands) |
| Carrying Amount | $2,210,196 |
| Fair Value | $2,633,904 |

## 5. Discontinued Operations

On August 1, 2012, we completed the sale of substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $129 million. The sale was previously announced on May 12, 2011. In connection with the sale, we expect to recognize a net of tax gain of approximately $6 million, subject to post-closing adjustments.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at June 30, 2012 and September 30, 2011.

The following table presents statement of income data related to discontinued operations.

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Operating revenues | $8,745 | $11,524 | $58,570 | $71,047 |
| Purchased gas cost | 3,005 | 5,460 | 34,982 | 44,993 |
| Gross profit | 5,740 | 6,064 | 23,588 | 26,054 |
| Operating expenses | 4,146 | 4,472 | 12,595 | 12,919 |
| Operating income | 1,594 | 1,592 | 10,993 | 13,135 |
| Other nonoperating expense | (40) | (94) | (126) | (159) |
| Income from discontinued operations before income taxes | 1,554 | 1,498 | 10,867 | 12,976 |
| Income tax expense | 566 | 590 | 3,959 | 5,122 |
| Net income | $ 988 | $ 908 | $ 6,908 | $ 7,854 |

The following table presents balance sheet data related to assets held for sale.

| | June 30, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Net plant, property & equipment | $126,685 | $127,577 |
| Gas stored underground | 5,746 | 11,931 |
| Other current assets | 2,998 | 786 |
| Deferred charges and other assets | 100 | 277 |
| Assets held for sale | $135,529 | $140,571 |
| Accounts payable and accrued liabilities | $ 1,526 | $ 1,917 |
| Other current liabilities | 8,722 | 4,877 |
| Regulatory cost of removal | 6,927 | 10,498 |
| Deferred credits and other liabilities | 869 | 1,153 |
| Liabilities held for sale | $ 18,044 | $ 18,445 |

On August 8, 2012, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur in fiscal 2013.

The following table presents the assets and liabilities associated with our Georgia operations as of June 30, 2012. As required under generally accepted accounting principles, the operating results and the assets and liabilities of our Georgia operations are classified as continuing operations at June 30, 2012.

| | June 30, 2012 |
|---|---|
| | (In thousands) |
| Net plant, property & equipment | $133,336 |
| Gas stored underground | 2,389 |
| Other current assets | 6,885 |
| Deferred charges and other assets | 112 |
| Total assets | $142,722 |
| Accounts payable and accrued liabilities | $ 1,570 |
| Other current liabilities | 3,275 |
| Regulatory cost of removal | 4,010 |
| Deferred credits and other liabilities | 296 |
| Total liabilities | $ 9,151 |

## 6. Debt

The nature and terms of our debt instruments are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes in the terms of our debt instruments during the nine months ended June 30, 2012.

***Long-term debt***

Long-term debt at June 30, 2012 and September 30, 2011 consisted of the following:

| | June 30, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Unsecured 10% Notes, redeemed December 2011 | $ — | $ 2,303 |
| Unsecured 5.125% Senior Notes, due January 2013 | 250,000 | 250,000 |
| Unsecured 4.95% Senior Notes, due 2014 | 500,000 | 500,000 |
| Unsecured 6.35% Senior Notes, due 2017 | 250,000 | 250,000 |
| Unsecured 8.50% Senior Notes, due 2019 | 450,000 | 450,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Unsecured 5.50% Senior Notes, due 2041 | 400,000 | 400,000 |
| Medium term notes | | |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| Rental property term note due in installments through 2013 | 196 | 262 |
| Total long-term debt | 2,210,196 | 2,212,565 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | (3,776) | (4,014) |
| Current maturities | (250,131) | (2,434) |
| | $1,956,289 | $2,206,117 |

Our unsecured 10% notes were paid on their maturity date on December 31, 2011 and were not replaced. As noted above, our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On July 27, 2012 we issued a notice of early redemption of these notes on August 28, 2012. We intend to initially fund the redemption through the issuance of commercial paper. Shortly thereafter, we intend to enter into a short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received from the issuance of new unsecured notes anticipated to occur in January 2013. In connection with the redemption, we will pay a make-whole premium in accordance with the terms of the indenture and the Senior Notes and accrued interest at the time of redemption. In accordance with regulatory requirements, the premium will be deferred and will be recognized over the life of the new unsecured notes expected to be issued in January 2013.

***Short-term debt***

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

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program collateralized by our $750 million unsecured credit facility and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $985 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At June 30, 2012 and September 30, 2011, there was $213.5 million and $206.4 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

***Regulated Operations***

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding, including a five-year $750 million unsecured facility, a $25 million unsecured facility and a $10 million revolving credit facility, which is used primarily to issue letters of credit. On July 25, 2012, we increased the borrowing capacity of our $10 million revolving credit facility to $14 million. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $2.5 million at June 30, 2012. Our $25 million unsecured facility was renewed effective April 1, 2012. This facility bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin.

In addition to these third-party facilities, our regulated operations had a $350 million intercompany revolving credit facility with AEH. This facility was replaced on January 1, 2012 with a $500 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

***Nonregulated Operations***

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility, expiring in December 2013, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH. Due to outstanding letters of credit and various covenants, including covenants based on working capital, the amount available to AEM under this credit facility was $94.6 million at June 30, 2012.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

***Shelf Registration***

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At June 30, 2012, $900 million remains available for issuance. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires in March 2013.

***Debt Covenants***

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2012, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 53 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

AEM is required by the financial covenants in its facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.77 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at June 30, 2012, AEM's net working capital was $122.0 million and its tangible net worth was $152.3 million.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

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

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

We were in compliance with all of our debt covenants as of June 30, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

## 7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities), we are required to use the two-class method of computing earnings per share. The Company's restricted stock units, for which vesting is predicated solely on the passage of time granted under our 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and nine months ended June 30, 2012 and 2011 are calculated as follows:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share amounts) | | | |
| **Basic Earnings Per Share from continuing operations** | | | | |
| Income (loss) from continuing operations | $30,144 | $(1,474) | $201,842 | $197,786 |
| Less: Income (loss) from continuing operations allocated to participating securities | 125 | (32) | 847 | 2,076 |
| Income (loss) from continuing operations available to common shareholders | $30,019 | $(1,442) | $200,995 | $195,710 |
| Basic weighted average shares outstanding | 90,118 | 90,127 | 90,131 | 90,233 |
| Income (loss) from continuing operations per share — Basic | $ 0.33 | $ (0.02) | $ 2.23 | $ 2.17 |
| **Basic Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations | $ 988 | $ 908 | $ 6,908 | $ 7,854 |
| Less: Income from discontinued operations allocated to participating securities | 4 | 20 | 29 | 82 |
| Income from discontinued operations available to common shareholders | $ 984 | $ 888 | $ 6,879 | $ 7,772 |
| Basic weighted average shares outstanding | 90,118 | 90,127 | 90,131 | 90,233 |
| Income from discontinued operations per share — Basic | $ 0.01 | $ 0.01 | $ 0.08 | $ 0.09 |
| Net income (loss) per share — Basic | $ 0.34 | $ (0.01) | $ 2.31 | $ 2.26 |

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share amounts) | | | |
| **Diluted Earnings Per Share from continuing operations** | | | | |
| Income (loss) from continuing operations available to common shareholders | $30,019 | $(1,442) | $200,995 | $195,710 |
| Effect of dilutive stock options and other shares | — | — | 5 | 4 |
| Income (loss) from continuing operations available to common shareholders | $30,019 | $(1,442) | $201,000 | $195,714 |
| Basic weighted average shares outstanding | 90,118 | 90,127 | 90,131 | 90,233 |
| Additional dilutive stock options and other shares | 875 | — | 875 | 297 |
| Diluted weighted average shares outstanding | 90,993 | 90,127 | 91,006 | 90,530 |
| Income (loss) from continuing operations per share — Diluted | $ 0.33 | $ (0.02) | $ 2.21 | $ 2.16 |
| **Diluted Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations available to common shareholders | $ 984 | $ 888 | $ 6,879 | $ 7,772 |
| Effect of dilutive stock options and other shares | — | 2 | — | — |
| Income from discontinued operations available to common shareholders | $ 984 | $ 890 | $ 6,879 | $ 7,772 |
| Basic weighted average shares outstanding | 90,118 | 90,127 | 90,131 | 90,233 |
| Additional dilutive stock options and other shares | 875 | — | 875 | 297 |
| Diluted weighted average shares outstanding | 90,993 | 90,127 | 91,006 | 90,530 |
| Income from discontinued operations per share — Diluted | $ 0.01 | $ 0.01 | $ 0.07 | $ 0.09 |
| Net income (loss) per share — Diluted | $ 0.34 | $ (0.01) | $ 2.28 | $ 2.25 |

There were approximately 288,000 stock options and other shares excluded from the computation of diluted earnings per share for the three months ended June 30, 2011 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2012 and 2011 as their exercise price was less than the average market price of the common stock during those periods.

***Share Repurchase Program***

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. However, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. As of June 30, 2012, a total of 387,991 shares had been repurchased for an aggregate value of $12.5 million.

## 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 and nine months ended June 30, 2012 and 2011 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

| | Three Months Ended June 30 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 4,297 | $ 4,257 | $ 4,089 | $ 3,601 |
| Interest cost | 6,677 | 7,055 | 3,465 | 3,204 |
| Expected return on assets | (5,368) | (6,285) | (651) | (681) |
| Amortization of transition asset | — | — | 377 | 377 |
| Amortization of prior service cost | (35) | (106) | (362) | (362) |
| Amortization of actuarial loss | 4,142 | 2,748 | 662 | 87 |
| Net periodic pension cost | $ 9,713 | $ 7,669 | $ 7,580 | $ 6,226 |

| | Nine Months Ended June 30 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 12,893 | $ 12,894 | $12,265 | $10,803 |
| Interest cost | 20,032 | 21,034 | 10,396 | 9,610 |
| Expected return on assets | (16,105) | (18,533) | (1,955) | (2,045) |
| Amortization of transition asset | — | — | 1,133 | 1,133 |
| Amortization of prior service cost | (106) | (323) | (1,087) | (1,087) |
| Amortization of actuarial loss | 12,427 | 8,990 | 1,986 | 260 |
| Curtailment gain | — | (40) | — | — |
| Net periodic pension cost | $ 29,141 | $ 24,022 | $22,738 | $18,674 |

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2012 and 2011 are as follows:

| | Pension Account Plan | | Other Pension Benefits | | Other Benefits | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Discount rate | 5.05% | 5.68% | 5.05% | 5.39% | 5.05% | 5.39% |
| Rate of compensation increase | 3.50% | 4.00% | 3.50% | 4.00% | N/A | N/A |
| Expected return on plan assets | 7.75% | 8.25% | 7.75% | 8.25% | 4.70% | 5.00% |

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the

Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based upon this valuation, we contributed $23.0 million to our defined benefit pension plans during the second fiscal quarter to achieve a desirable PPA funding threshold. The need for this funding reflects the increased pension benefit obligation due to a decrease in the discount rate compared to the prior year as well as a decline in the fair value of plan assets. During the first nine months of fiscal 2012, we contributed $40.3 million to our defined benefit plans and we anticipate contributing approximately $6 million during the remainder of the fiscal year.

We contributed $15.4 million to our other post-retirement benefit plans during the nine months ended June 30, 2012. We expect to contribute a total of approximately $5 million to $10 million to these plans during the remainder of the fiscal year.

## 9. Commitments and Contingencies

### *Litigation and Environmental Matters*

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2012.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky, *Billy Joe Honeycutt et al. vs. Atmos Energy Corporation, et al.*, which is related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

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

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

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter. However, we continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

***Purchase Commitments***

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2012, AEH was committed to purchase 79.2 Bcf within one year, 17.7 Bcf within one to three years and 0.1 Bcf after three years under indexed contracts. AEH is committed to purchase 2.7 Bcf within one year and 0.4 Bcf within one to three years under fixed price contracts with prices ranging from $2.50 to $6.36 per Mcf. Purchases under these contracts totaled $176.6 million and $356.8 million for the three months ended June 30, 2012 and 2011 and $753.0 million and $1,130.0 million for the nine months ended June 30, 2012 and 2011.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2012 are as follows (in thousands):

| | |
|---|---|
| 2012 | $ 33,563 |
| 2013 | 241,797 |
| 2014 | 70,633 |
| 2015 | — |
| 2016 | — |
| Thereafter | — |
| | $345,993 |

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2012.

***Regulatory Matters***

As previously described in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

As discussed in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in 2010, our Mid-Tex Division agreed to install 100,000 steel service line replacements by September 30, 2012. As of June 30, 2012, we had replaced 88,312 lines and are on schedule for completion in September 2012. Under the terms of the agreement, special rate recovery of the associated return, depreciation and taxes is approved for lines replaced between October 1, 2010 and September 30, 2012. Since October 1, 2010, we have spent $100.5 million on steel service line replacements.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodity Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the SEC and CFTC have issued a number of rules and regulations, we expect additional rules and regulations to be issued, which should provide additional clarity regarding the extent of the impact of this legislation on the Company. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation and related rules and regulations. Additional reporting and disclosure obligations have been imposed upon the Company, the full extent of which will not be known until the SEC and the CFTC have completed their ongoing rulemaking process.

As of June 30, 2012, rate cases were in progress in our Mid-Tex, West Texas, Kansas and Tennessee service areas, an annual rate filing mechanism was in progress in our Louisiana service area and one infrastructure program filing was in progress in our Georgia service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

## 10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the nine months ended June 30, 2012, there were no material changes in our concentration of credit risk.

## 11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,

- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine month periods ended June 30, 2012 and 2011 by segment are presented in the following tables:

| | Three Months Ended June 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $324,837 | $26,551 | $234,443 | $ — | $585,831 |
| Intersegment revenues | 214 | 40,522 | 21,807 | (62,543) | — |
| | 325,051 | 67,073 | 256,250 | (62,543) | 585,831 |
| Purchased gas cost | 124,373 | — | 224,829 | (62,161) | 287,041 |
| Gross profit | 200,678 | 67,073 | 31,421 | (382) | 298,790 |
| Operating expenses | | | | | |
| Operation and maintenance | 83,474 | 16,427 | 7,777 | (383) | 107,295 |
| Depreciation and amortization | 51,020 | 7,797 | 1,002 | — | 59,819 |
| Taxes, other than income | 42,274 | 3,839 | 774 | — | 46,887 |
| Total operating expenses | 176,768 | 28,063 | 9,553 | (383) | 214,001 |
| Operating income | 23,910 | 39,010 | 21,868 | 1 | 84,789 |
| Miscellaneous income (expense) | (926) | (298) | 136 | (860) | (1,948) |
| Interest charges | 27,834 | 7,353 | 595 | (859) | 34,923 |
| Income (loss) from continuing operations before income taxes | (4,850) | 31,359 | 21,409 | — | 47,918 |
| Income tax expense (benefit) | (2,073) | 11,215 | 8,632 | — | 17,774 |
| Income (loss) from continuing operations | (2,777) | 20,144 | 12,777 | — | 30,144 |
| Income from discontinued operations, net of tax | 988 | — | — | — | 988 |
| Net income (loss) | $ (1,789) | $20,144 | $ 12,777 | $ — | $ 31,132 |
| Capital expenditures | $149,531 | $34,191 | $ 2,529 | $ — | $186,251 |

| | Three Months Ended June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $406,817 | $19,772 | $417,026 | $ — | $843,615 |
| Intersegment revenues | 214 | 33,798 | 74,259 | (108,271) | — |
| | 407,031 | 53,570 | 491,285 | (108,271) | 843,615 |
| Purchased gas cost | 206,839 | — | 477,880 | (107,909) | 576,810 |
| Gross profit | 200,192 | 53,570 | 13,405 | (362) | 266,805 |
| Operating expenses | | | | | |
| Operation and maintenance | 86,804 | 18,786 | 7,437 | (362) | 112,665 |
| Depreciation and amortization | 49,099 | 6,790 | 1,043 | — | 56,932 |
| Taxes, other than income | 47,534 | 3,729 | 879 | — | 52,142 |
| Asset impairments | — | — | 10,988 | — | 10,988 |
| Total operating expenses | 183,437 | 29,305 | 20,347 | (362) | 232,727 |
| Operating income (loss) | 16,755 | 24,265 | (6,942) | — | 34,078 |
| Miscellaneous income (expense) | (1,153) | (312) | 168 | (133) | (1,430) |
| Interest charges | 28,042 | 7,653 | 283 | (133) | 35,845 |
| Income (loss) from continuing operations before income taxes | (12,440) | 16,300 | (7,057) | — | (3,197) |
| Income tax expense (benefit) | (4,311) | 5,748 | (3,160) | — | (1,723) |
| Income (loss) from continuing operations | (8,129) | 10,552 | (3,897) | — | (1,474) |
| Income from discontinued operations, net of tax | 908 | — | — | — | 908 |
| Net income (loss) | $ (7,221) | $10,552 | $ (3,897) | $ — | $ (566) |
| Capital expenditures | $121,452 | $20,239 | $ 1,929 | $ — | $143,620 |

| | Nine Months Ended June 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $1,906,590 | $ 66,421 | $ 957,443 | $ — | $2,930,454 |
| Intersegment revenues | 761 | 115,448 | 113,746 | (229,955) | — |
| | 1,907,351 | 181,869 | 1,071,189 | (229,955) | 2,930,454 |
| Purchased gas cost | 1,034,786 | — | 1,028,592 | (228,857) | 1,834,521 |
| Gross profit | 872,565 | 181,869 | 42,597 | (1,098) | 1,095,933 |
| Operating expenses | | | | | |
| Operation and maintenance | 266,331 | 49,239 | 19,597 | (1,102) | 334,065 |
| Depreciation and amortization | 153,606 | 23,240 | 2,460 | — | 179,306 |
| Taxes, other than income | 131,066 | 11,538 | 2,400 | — | 145,004 |
| Total operating expenses | 551,003 | 84,017 | 24,457 | (1,102) | 658,375 |
| Operating income | 321,562 | 97,852 | 18,140 | 4 | 437,558 |
| Miscellaneous income (expense) | (1,949) | (634) | 739 | (1,363) | (3,207) |
| Interest charges | 84,522 | 22,176 | 1,686 | (1,359) | 107,025 |
| Income from continuing operations before income taxes | 235,091 | 75,042 | 17,193 | — | 327,326 |
| Income tax expense | 91,662 | 26,864 | 6,958 | — | 125,484 |
| Income from continuing operations | 143,429 | 48,178 | 10,235 | — | 201,842 |
| Income from discontinued operations, net of tax | 6,908 | — | — | — | 6,908 |
| Net income | $ 150,337 | $ 48,178 | $ 10,235 | $ — | $ 208,750 |
| Capital expenditures | $ 392,666 | $ 97,182 | $ 7,526 | $ — | $ 497,374 |

| | Nine Months Ended June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $2,187,256 | $ 62,602 | $1,308,516 | $ — | $3,558,374 |
| Intersegment revenues | 651 | 94,951 | 241,940 | (337,542) | — |
| | 2,187,907 | 157,553 | 1,550,456 | (337,542) | 3,558,374 |
| Purchased gas cost | 1,317,775 | — | 1,491,815 | (336,413) | 2,473,177 |
| Gross profit | 870,132 | 157,553 | 58,641 | (1,129) | 1,085,197 |
| Operating expenses | | | | | |
| Operation and maintenance | 268,299 | 49,591 | 24,556 | (1,129) | 341,317 |
| Depreciation and amortization | 145,548 | 18,387 | 3,241 | — | 167,176 |
| Taxes, other than income | 132,070 | 11,395 | 2,403 | — | 145,868 |
| Asset impairments | — | — | 30,270 | — | 30,270 |
| Total operating expenses | 545,917 | 79,373 | 60,470 | (1,129) | 684,631 |
| Operating income (loss) | 324,215 | 78,180 | (1,829) | — | 400,566 |
| Miscellaneous income | 18,305 | 5,267 | 764 | (290) | 24,046 |
| Interest charges | 87,344 | 23,802 | 1,759 | (290) | 112,615 |
| Income (loss) from continuing operations before income taxes | 255,176 | 59,645 | (2,824) | — | 311,997 |
| Income tax expense (benefit) | 94,323 | 21,252 | (1,364) | — | 114,211 |
| Income (loss) from continuing operations | 160,853 | 38,393 | (1,460) | — | 197,786 |
| Income from discontinued operations, net of tax | 7,854 | — | — | — | 7,854 |
| Net income (loss) | $ 168,707 | $ 38,393 | $ (1,460) | $ — | $ 205,640 |
| Capital expenditures | $ 340,713 | $ 44,796 | $ 4,774 | $ — | $ 390,283 |

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at June 30, 2012 and September 30, 2011 by segment is presented to reflect our business structure as of June 30, 2012 in the following tables.

| | June 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,464,707 | $ 910,689 | $ 66,490 | $ — | $5,441,886 |
| Investment in subsidiaries | 725,348 | — | (2,096) | (723,252) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 9,245 | — | 18,461 | — | 27,706 |
| Assets from risk management activities | 3,486 | — | 3,939 | — | 7,425 |
| Other current assets | 519,422 | 16,021 | 424,455 | (219,371) | 740,527 |
| Intercompany receivables | 595,944 | — | — | (595,944) | — |
| Total current assets | 1,128,097 | 16,021 | 446,855 | (815,315) | 775,658 |
| Intangible assets | — | — | 174 | — | 174 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | 1,207 | — | 6,025 | — | 7,232 |
| Deferred charges and other assets | 358,272 | 16,379 | 10,234 | — | 384,885 |
| | $7,250,539 | $1,075,470 | $562,393 | $(1,538,567) | $7,349,835 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,354,925 | $ 313,280 | $412,068 | $ (725,348) | $2,354,925 |
| Long-term debt | 1,956,224 | — | 65 | — | 1,956,289 |
| Total capitalization | 4,311,149 | 313,280 | 412,133 | (725,348) | 4,311,214 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 250,000 | — | 131 | — | 250,131 |
| Short-term debt | 422,491 | — | — | (209,000) | 213,491 |
| Liabilities from risk management activities | 96,895 | — | 4,658 | — | 101,553 |
| Other current liabilities | 435,743 | 8,440 | 109,146 | (8,275) | 545,054 |
| Intercompany payables | — | 559,281 | 36,663 | (595,944) | — |
| Total current liabilities | 1,205,129 | 567,721 | 150,598 | (813,219) | 1,110,229 |
| Deferred income taxes | 898,176 | 192,981 | (5,503) | — | 1,085,654 |
| Noncurrent liabilities from risk management activities | — | — | 4,182 | — | 4,182 |
| Regulatory cost of removal obligation | 381,797 | — | — | — | 381,797 |
| Deferred credits and other liabilities | 454,288 | 1,488 | 983 | — | 456,759 |
| | $7,250,539 | $1,075,470 | $562,393 | $(1,538,567) | $7,349,835 |

| | September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,248,198 | $ 838,302 | $ 61,418 | $ — | $5,147,918 |
| Investment in subsidiaries | 670,993 | — | (2,096) | (668,897) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 24,646 | — | 106,773 | — | 131,419 |
| Assets from risk management activities | 843 | — | 17,501 | — | 18,344 |
| Other current assets | 655,716 | 15,413 | 386,215 | (196,154) | 861,190 |
| Intercompany receivables | 569,898 | — | — | (569,898) | — |
| Total current assets | 1,251,103 | 15,413 | 510,489 | (766,052) | 1,010,953 |
| Intangible assets | — | — | 207 | — | 207 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | 998 | — | — | — | 998 |
| Deferred charges and other assets | 353,960 | 18,028 | 10,807 | — | 382,795 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,255,421 | $ 265,102 | $405,891 | $ (670,993) | $2,255,421 |
| Long-term debt | 2,205,986 | — | 131 | — | 2,206,117 |
| Total capitalization | 4,461,407 | 265,102 | 406,022 | (670,993) | 4,461,538 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 2,303 | — | 131 | — | 2,434 |
| Short-term debt | 387,691 | — | — | (181,295) | 206,396 |
| Liabilities from risk management activities | 11,916 | — | 3,537 | — | 15,453 |
| Other current liabilities | 474,783 | 10,369 | 170,926 | (12,763) | 643,315 |
| Intercompany payables | — | 543,084 | 26,814 | (569,898) | — |
| Total current liabilities | 876,693 | 553,453 | 201,408 | (763,956) | 867,598 |
| Deferred income taxes | 789,649 | 173,351 | (2,907) | — | 960,093 |
| Noncurrent liabilities from risk management activities | 67,862 | — | 10,227 | — | 78,089 |
| Regulatory cost of removal obligation | 428,947 | — | — | — | 428,947 |
| Deferred credits and other liabilities | 473,602 | 12,218 | 786 | — | 486,606 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of June 30, 2012, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2012 and 2011, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2012 and 2011. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2011, 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 22, 2011, 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, 2011, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
August 9, 2012

## 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, 2011.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

## OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which at June 30, 2012 covered service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. On August 1, 2012, we completed the divestiture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. On August 8, 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

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

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed periodically by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2012.

## RESULTS OF OPERATIONS

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, normally peaks in November and declines as we utilize storage gas to serve our customers.

The seasonality of our business usually results in a loss in our fiscal third quarter. However, we reported net income of $31.1 million, or $0.34 per diluted share for the three months ended June 30, 2012, compared with a net loss of $0.6 million or $0.01 per diluted share in the prior year. Excluding the impact of unrealized margins and one-time items that occurred in the prior-year quarter, diluted earnings per share increased $0.27 compared to the prior-year quarter. The quarter-over-quarter improvement reflects higher gross profit in our regulated transmission and storage segment due to increases approved under the Gas Reliability Infrastructure Program and in our nonregulated segment due to increased asset optimization, combined with lower consolidated operation and maintenance expense, which more than offset lower natural gas distribution margins. We reported net income from discontinued operations associated with the sale of our Missouri, Illinois and Iowa service areas of $1.0 million and $0.9 million, or $0.01 per diluted share, for the three months ended June 30, 2012 and 2011.

During the nine months ended June 30, 2012, we earned $208.8 million or $2.28 per diluted share. Results for the prior-year period were influenced by the net positive impact of several one-time items totaling $6.5 million, or $0.07 per diluted share. Excluding the impact of these one-time items and unrealized margins in our nonregulated operations, we earned $201.7 million, or $2.20 per diluted share for the nine months ended June 30, 2012, compared to $200.6 million, or $2.20 in the prior-year period. Included in the current period amount is net income from discontinued operations of $6.9 million, or $0.07 per diluted share associated with the sale of our Missouri, Illinois and Iowa service areas, a decrease of $0.9 million or $0.02 per diluted share compared with the prior-year period.

Our year-to-date results were unfavorably impacted by substantially warmer winter weather and an abundance of natural gas supply. The impact of these conditions was most significantly realized in our nonregulated operations, which experienced a $12.4 million nine-month period-over-period decrease in net income, excluding the impact of one-time items and unrealized margins. However, increased earnings in our regulated transmission and storage segment, primarily as a result of an improved rate design implemented in the third quarter of the prior fiscal year, more than offset the decline experienced in our nonregulated segment. Results in our natural gas distribution segment, excluding the impact of one-time items were flat compared to the prior year, despite a nine percent decrease in throughput largely attributable to warmer than normal weather.

During the current fiscal year, we have taken several steps to increase earnings in our regulated operations. In our natural gas distribution segment, we have six rate proceedings in progress requesting a total of $75.6 million in additional annual operating income and, in April 2012, we completed an annual rate filing for Atmos Pipeline-Texas (APT) that should increase annual operating income by $14.7 million. Further, we announced two significant pipeline expansion projects whereby APT will spend approximately $160 million over the next two fiscal years to increase its ability to secure new long-term gas supply on a firm and reliable basis and to enhance the reliability of APT's service to our Mid-Tex Division in certain critical locations.

During the second fiscal quarter, we completed the annual evaluation of the funded status of our qualified defined benefit plans as of January 1, 2012 as required by the Pension Protection Act of 2006 (PPA). As a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our pension liabilities, we were required to contribute $23.0 million into the plans. For the nine months ended June 30, 2012, we contributed $40.3 million into these plans and expect to contribute approximately $6 million for the remainder of the fiscal year. Additionally, we contributed $15.4 million into our postretirement medical plans during the nine months ended June 30, 2012 and expect to contribute between $5 million and $10 million for the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

**Consolidated Results**

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2012 and 2011:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share data) | | | |
| Operating revenues | $585,831 | $843,615 | $2,930,454 | $3,558,374 |
| Gross profit | 298,790 | 266,805 | 1,095,933 | 1,085,197 |
| Operating expenses | 214,001 | 232,727 | 658,375 | 684,631 |
| Operating income | 84,789 | 34,078 | 437,558 | 400,566 |
| Miscellaneous income (expense) | (1,948) | (1,430) | (3,207) | 24,046 |
| Interest charges | 34,923 | 35,845 | 107,025 | 112,615 |
| Income (loss) from continuing operations before income taxes | 47,918 | (3,197) | 327,326 | 311,997 |
| Income tax expense (benefit) | 17,774 | (1,723) | 125,484 | 114,211 |
| Income (loss) from continuing operations | 30,144 | (1,474) | 201,842 | 197,786 |
| Income from discontinued operations, net of tax | 988 | 908 | 6,908 | 7,854 |
| Net income (loss) | $ 31,132 | $ (566) | $ 208,750 | $ 205,640 |
| Diluted net income (loss) per share from continuing operations | $ 0.33 | $ (0.02) | $ 2.21 | $ 2.16 |
| Diluted net income per share from discontinued operations | 0.01 | 0.01 | 0.07 | 0.09 |
| Diluted net income (loss) per share | $ 0.34 | $ (0.01) | $ 2.28 | $ 2.25 |

Our consolidated net income (loss) during the three and nine month periods ended June 30, 2012 and 2011 was earned in each of our business segments as follows:

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Natural gas distribution segment from continuing operations | $ (2,777) | $ (8,129) | $ 5,352 |
| Regulated transmission and storage segment | 20,144 | 10,552 | 9,592 |
| Nonregulated segment | 12,777 | (3,897) | 16,674 |
| Net income (loss) from continuing operations | 30,144 | (1,474) | 31,618 |
| Net income from discontinued operations | 988 | 908 | 80 |
| Net income (loss) | $ 31,132 | $ (566) | $ 31,698 |

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Natural gas distribution segment from continuing operations | $143,429 | $160,853 | $(17,424) |
| Regulated transmission and storage segment | 48,178 | 38,393 | 9,785 |
| Nonregulated segment | 10,235 | (1,460) | 11,695 |
| Net income from continuing operations | 201,842 | 197,786 | 4,056 |
| Net income from discontinued operations | 6,908 | 7,854 | (946) |
| Net income | $208,750 | $205,640 | $ 3,110 |

Regulated operations contributed 59 percent and 95 percent to our consolidated net income for the three and nine month periods ended June 30, 2012. The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $17,367 | $ 2,423 | $14,944 |
| Nonregulated operations | 12,777 | (3,897) | 16,674 |
| Net income (loss) from continuing operations | 30,144 | (1,474) | 31,618 |
| Net income from discontinued operations | 988 | 908 | 80 |
| Net income (loss) | $31,132 | $ (566) | $31,698 |
| Diluted EPS from continuing regulated operations | $ 0.19 | $ 0.02 | $ 0.17 |
| Diluted EPS from nonregulated operations | 0.14 | (0.04) | 0.18 |
| Diluted EPS from continuing operations | 0.33 | (0.02) | 0.35 |
| Diluted EPS from discontinued operations | 0.01 | 0.01 | — |
| Consolidated diluted EPS | $ 0.34 | $ (0.01) | $ 0.35 |

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $191,607 | $199,246 | $ (7,639) |
| Nonregulated operations | 10,235 | (1,460) | 11,695 |
| Net income from continuing operations | 201,842 | 197,786 | 4,056 |
| Net income from discontinued operations | 6,908 | 7,854 | (946) |
| Net income | $208,750 | $205,640 | $ 3,110 |
| Diluted EPS from continuing regulated operations | $ 2.10 | $ 2.18 | $ (0.08) |
| Diluted EPS from nonregulated operations | 0.11 | (0.02) | 0.13 |
| Diluted EPS from continuing operations | 2.21 | 2.16 | 0.05 |
| Diluted EPS from discontinued operations | 0.07 | 0.09 | (0.02) |
| Consolidated diluted EPS | $ 2.28 | $ 2.25 | $ 0.03 |

### *Natural Gas Distribution Segment*

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

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for over 90 percent of our residential and commercial meters in the following states for the following time periods:

| | |
|---|---|
| Georgia, Kansas, West Texas | October — May |
| Kentucky, Mississippi, Tennessee, Mid-Tex | November — April |
| Louisiana | December — March |
| Virginia | January — December |

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources. Conversely, lower gas costs reduce our collection risk and reduce the need to utilize short-term borrowings to fund our working capital needs.

As discussed above, on August 1, 2012, we completed the sale of substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

On August 8, 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia. The results of these operations are classified as continuing operations at June 30, 2012.

***Three Months Ended June 30, 2012 compared with Three Months Ended June 30, 2011***

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2012 and 2011 are presented below.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $200,678 | $200,192 | $ 486 |
| Operating expenses | 176,768 | 183,437 | (6,669) |
| **Operating income** | 23,910 | 16,755 | 7,155 |
| Miscellaneous expense | (926) | (1,153) | 227 |
| Interest charges | 27,834 | 28,042 | (208) |
| **Loss from continuing operations before income taxes** | (4,850) | (12,440) | 7,590 |
| Income tax benefit | (2,073) | (4,311) | 2,238 |
| **Loss from continuing operations** | (2,777) | (8,129) | 5,352 |
| Income from discontinued operations, net of tax | 988 | 908 | 80 |
| **Net loss** | $ (1,789) | $ (7,221) | $ 5,432 |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 33,407 | 37,011 | (3,604) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 30,312 | 29,955 | 357 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 63,719 | 66,966 | (3,247) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 1,981 | 2,128 | (147) |
| Total consolidated natural gas distribution throughput — MMcf | 65,700 | 69,094 | (3,394) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.43 | $ 0.46 | $ (0.03) |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 3.73 | $ 5.59 | $ (1.86) |

The $0.5 million increase in natural gas distribution gross profit was primarily due to a $4.5 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky, Louisiana and Mississippi service areas.

These increases were partially offset by a $3.3 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.

Results for the third fiscal quarter were also unfavorably impacted by a five percent decrease in total consolidated throughput compared to the prior year. However, the impact to gross profit was mitigated by favorable rate designs that substantially lessened the impact of warm weather in most of our natural gas distribution service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $6.7 million primarily due to the following:

- $5.3 million decrease in taxes, other than income.

- $1.4 million decrease in legal costs.
- $1.4 million decrease due to the establishment of regulatory assets for pension and postretirement costs.

These decreases were partially offset by a $1.9 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended June 30, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | | (In thousands) | |
| Mid-Tex | $ 5,845 | $ 759 | $ 5,086 |
| Kentucky/Mid-States | 5,189 | 4,832 | 357 |
| Louisiana | 6,880 | 6,779 | 101 |
| West Texas | 353 | 605 | (252) |
| Mississippi | 1,785 | (615) | 2,400 |
| Colorado-Kansas | 1,466 | 3,304 | (1,838) |
| Other | 2,392 | 1,091 | 1,301 |
| Total | $23,910 | $16,755 | $ 7,155 |

*Nine Months Ended June 30, 2012 compared with Nine Months Ended June 30, 2011*

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2012 and 2011 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $872,565 | $870,132 | $ 2,433 |
| Operating expenses | 551,003 | 545,917 | 5,086 |
| **Operating income** | 321,562 | 324,215 | (2,653) |
| Miscellaneous income (expense) | (1,949) | 18,305 | (20,254) |
| Interest charges | 84,522 | 87,344 | (2,822) |
| **Income from continuing operations before income taxes** | 235,091 | 255,176 | (20,085) |
| Income tax expense | 91,662 | 94,323 | (2,661) |
| **Income from continuing operations** | 143,429 | 160,853 | (17,424) |
| Income from discontinued operations, net of tax | 6,908 | 7,854 | (946) |
| **Net income** | $150,337 | $168,707 | $(18,370) |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 221,466 | 253,665 | (32,199) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 100,021 | 99,551 | 470 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 321,487 | 353,216 | (31,729) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 10,855 | 12,723 | (1,868) |
| Total consolidated natural gas distribution throughput — MMcf | 332,342 | 365,939 | (33,597) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.44 | $ 0.47 | $ (0.03) |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 4.70 | $ 5.21 | $ (0.51) |

The $2.4 million increase in natural gas distribution gross profit was primarily due to a $15.5 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Mississippi, Kentucky and West Texas service areas.

These increases were partially offset by the following:

- $8.9 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.
- $3.1 million decrease due to a nine percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in the current period compared to the same period last year in most of our service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $5.1 million primarily due to the following:

- $8.1 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.

- $5.9 million net increase in legal and other administrative costs.
- $1.7 million increase in software maintenance costs.

These increases were partially offset by the following:

- $5.5 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.
- $2.9 million decrease associated with the aforementioned regulatory asset.

Net income for this segment for the prior-year period was favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks ($13.3 million, net of tax) and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the nine months ended June 30, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Mid-Tex | $142,595 | $140,674 | $ 1,921 |
| Kentucky/Mid-States | 46,162 | 50,522 | (4,360) |
| Louisiana | 44,551 | 44,975 | (424) |
| West Texas | 29,017 | 29,405 | (388) |
| Mississippi | 29,454 | 27,604 | 1,850 |
| Colorado-Kansas | 23,627 | 26,256 | (2,629) |
| Other | 6,156 | 4,779 | 1,377 |
| Total | $321,562 | $324,215 | $(2,653) |

*Recent Ratemaking Developments*

Significant ratemaking developments that occurred during the nine months ended June 30, 2012 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $9.9 million resulting from ratemaking activity became effective in the nine months ended June 30, 2012 as summarized below:

| Rate Action | Annual Increase to Operating Income |
|---|---|
| | (In thousands) |
| Rate case filings | $ 545 |
| Infrastructure programs | 4,488 |
| Annual rate filing mechanisms | 4,720 |
| Other rate activity | 167 |
| | $9,920 |

Additionally, the following ratemaking efforts were in progress during the third quarter of fiscal 2012 but had not been completed as of June 30, 2012.

| Division | Rate Action | Jurisdiction | Operating Income Requested |
|---|---|---|---|
| | | | (In thousands) |
| Mid-Tex | Rate Case | RRC | $46,537 |
| West Texas | Rate Case | RRC | 9,427 |
| Colorado-Kansas | Rate Case[1] | Kansas | 5,498 |
| Louisiana | Rate Stabilization Clause[2] | LGS | 1,823 |
| Kentucky/Mid-States | PRP[3] | Georgia | 1,079 |
| Kentucky/Mid-States | Rate Case | Tennessee | 11,230 |
| | | | $75,594 |

(1) Atmos Energy and Commission Staff reached a settlement for an increase in operating income of $3.8 million. A hearing on the settlement was conducted on July 18, 2012 and a final order is due before the end of the fiscal year.

(2) The Louisiana Commission Staff recommended an operating income increase of $2.3 million effective July 1, 2012, which the Commission accepted.

(3) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

*Rate Case Filings*

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate case that was completed during the nine months ended June 30, 2012.

| Division | State | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|
| | | (In thousands) | |
| *2012 Rate Case Filings:* | | | |
| West Texas — Environs | Texas | $545 | 11/08/2011 |
| Total 2012 Rate Case Filings | | $545 | |

*Infrastructure Programs*

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. As of June 30, 2012, we had infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates occurring during the nine months ended June 30, 2012.

| Division | Period End | Incremental Net Utility Plant Investment | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | (In thousands) | (In thousands) | |
| *2012 Infrastructure Programs:* | | | | |
| Mid-Tex Unincorporated (Environs)[1] ... | 12/2011 | $145,671 | $ 744 | 06/26/2012 |
| Kentucky/Mid-States — Georgia ....... | 09/2010 | 7,160 | 1,215 | 10/01/2011 |
| Kentucky/Mid-States — Kentucky ...... | 09/2012 | 17,347 | 2,529 | 10/01/2011 |
| Total 2012 Infrastructure Programs .... | | $170,178 | $4,488 | |

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

*Annual Rate Filing Mechanisms*

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and the Georgia service area in our Kentucky/Mid-States Division. The Company is requesting new annual rate filing mechanisms as part of our ongoing rate cases in our Mid-Tex and West Texas divisions to replace the annual mechanisms that expired for significant portions of these service areas in 2011. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the nine months ended June 30, 2012.

| Division | Jurisdiction | Test Year Ended | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2012 Filings:* | | | | |
| Mid-Tex ......................... | Dallas | 09/30/2011 | $1,204 | 06/01/2012 |
| Louisiana .......................... | Trans La | 09/30/2011 | 11 | 04/01/2012 |
| Kentucky/Mid-States ................ | Georgia | 09/30/2011 | (818) | 02/01/2012 |
| Mississippi ........................ | Mississippi | 06/30/2011 | 4,323 | 01/11/2012 |
| Total 2012 Filings ................. | | | $4,720 | |

*Other Ratemaking Activity*

The following table summarizes other ratemaking activity during the nine months ended June 30, 2012:

| Division | Jurisdiction | Rate Activity | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2012 Other Rate Activity:* | | | | |
| Colorado-Kansas .................... | Kansas | Ad Valorem[1] | $167 | 01/14/2012 |
| Total 2012 Other Rate Activity ....... | | | $167 | |

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas area's base rates.

***Regulated Transmission and Storage Segment***

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

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

***Three Months Ended June 30, 2012 compared with Three Months Ended June 30, 2011***

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2012 and 2011 are presented below.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation ................................ | $ 43,693 | $ 32,098 | $11,595 |
| Third-party transportation .............................. | 17,281 | 16,518 | 763 |
| Storage and park and lend services ........................ | 1,484 | 1,802 | (318) |
| Other ............................................... | 4,615 | 3,152 | 1,463 |
| **Gross profit** ......................................... | 67,073 | 53,570 | 13,503 |
| Operating expenses .................................. | 28,063 | 29,305 | (1,242) |
| **Operating income** .................................... | 39,010 | 24,265 | 14,745 |
| Miscellaneous expense ................................. | (298) | (312) | 14 |
| Interest charges ....................................... | 7,353 | 7,653 | (300) |
| **Income before income taxes** ........................... | 31,359 | 16,300 | 15,059 |
| Income tax expense .................................... | 11,215 | 5,748 | 5,467 |
| **Net income** .......................................... | $ 20,144 | $ 10,552 | $ 9,592 |
| Gross pipeline transportation volumes — MMcf .............. | 146,170 | 141,294 | 4,876 |
| Consolidated pipeline transportation volumes — MMcf ........ | 118,678 | 112,564 | 6,114 |

The $13.5 million increase in regulated transmission and storage gross profit compared to the prior-year quarter was primarily a result of the GRIP filings approved by the RRC during fiscal 2011 and 2012. During fiscal 2011, the Commission approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $12.6 million that went into effect in the fiscal fourth quarter. On April 10, 2012, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $14.7 million that went into effect with bills rendered on and after April 10, 2012.

The GRIP filings approved in fiscal 2011 and 2012 increased quarter-over-quarter gross profit by $9.1 million. In addition, excess retention gas sales increased gross profit by $1.6 million.

Operating expenses decreased $1.2 million primarily due to a $2.6 million decrease in outside services and materials and supplies as a result of increased capital spending in the current-year quarter, partially offset by a $1.0 million increase in depreciation expense, resulting from the rate case and a higher investment in plant.

***Nine Months Ended June 30, 2012 compared with Nine Months Ended June 30, 2011***

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2012 and 2011 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $120,150 | $ 92,729 | $27,421 |
| Third-party transportation | 46,529 | 49,841 | (3,312) |
| Storage and park and lend services | 5,157 | 6,191 | (1,034) |
| Other | 10,033 | 8,792 | 1,241 |
| **Gross profit** | 181,869 | 157,553 | 24,316 |
| Operating expenses | 84,017 | 79,373 | 4,644 |
| **Operating income** | 97,852 | 78,180 | 19,672 |
| Miscellaneous income (expense) | (634) | 5,267 | (5,901) |
| Interest charges | 22,176 | 23,802 | (1,626) |
| **Income before income taxes** | 75,042 | 59,645 | 15,397 |
| Income tax expense | 26,864 | 21,252 | 5,612 |
| **Net income** | $ 48,178 | $ 38,393 | $ 9,785 |
| Gross pipeline transportation volumes — MMcf | 483,360 | 468,943 | 14,417 |
| Consolidated pipeline transportation volumes — MMcf | 333,341 | 305,898 | 27,443 |

The $24.3 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the previously discussed rate design changes approved in the rate case in the prior year. Therefore, despite an eight percent decrease in throughput to our Mid-Tex Division, we experienced a 30 percent increase in gross profit from Mid-Tex transportation.

For the year-to-date period, the enhanced rate design resulted in a $32.4 million increase in gross profit compared to the prior-year period. This increase was partially offset by the following:

- $4.4 million decrease in third-party transportation fees. Throughput associated with third-party transportation increased nine percent due to the execution of new delivery contracts with local producers in the Barnett Shale region. However, these increases were more than offset by lower transportation rates.
- $2.5 million decrease associated with lower throughput to our Mid-Tex Division.

Operating expenses increased $4.6 million primarily due to a $4.9 million increase in depreciation expense, resulting from the rate case and a higher investment in net plant.

Net income for this segment for the prior-year period was favorably impacted by a $6.0 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks ($3.9 million, net of tax).

### *Nonregulated Segment*

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. This business is significantly influenced by competitive factors in the industry, general economic conditions and other factors that could affect the demand for natural gas. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas used to serve those customers. Further, delivered gas margins can be affected by the price of natural gas in the different locations where we buy and sell gas.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions. These margins are influenced by natural gas market conditions including, but not limited to, the price of natural gas, demand for natural gas, the level of domestic natural gas inventory levels and the level of volatility between current (spot) and future natural gas prices. These margins are also impacted by our ability to minimize the demand fees paid to contract for storage capacity.

Higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices may also cause customers to conserve or use alternative energy sources. Lower natural gas prices generally reduce these risks.

The level of volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads and basis differentials from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Conversely, a lack of price volatility reduces opportunities to create value from arbitrage spreads and basis differentials.

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

*Three Months Ended June 30, 2012 compared with Three Months Ended June 30, 2011*

Financial and operational highlights for our nonregulated segment for the three months ended June 30, 2012 and 2011 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 9,637 | $ 11,631 | $ (1,994) |
| Storage and transportation services | 3,313 | 4,042 | (729) |
| Other | 791 | 1,177 | (386) |
| | 13,741 | 16,850 | (3,109) |
| Asset optimization[1] | 14,600 | (3,623) | 18,223 |
| **Total realized margins** | 28,341 | 13,227 | 15,114 |
| **Unrealized margins** | 3,080 | 178 | 2,902 |
| **Gross profit** | 31,421 | 13,405 | 18,016 |
| Operating expenses, excluding asset impairments | 9,553 | 9,359 | 194 |
| Asset impairments | — | 10,988 | (10,988) |
| **Operating income (loss)** | 21,868 | (6,942) | 28,810 |
| Miscellaneous income | 136 | 168 | (32) |
| Interest charges | 595 | 283 | 312 |
| **Income (loss) before income taxes** | 21,409 | (7,057) | 28,466 |
| Income tax expense (benefit) | 8,632 | (3,160) | 11,792 |
| **Net income (loss)** | $12,777 | $ (3,897) | $ 16,674 |
| Gross nonregulated delivered gas sales volumes — MMcf | 89,682 | 104,658 | (14,976) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 79,658 | 88,382 | (8,724) |
| Net physical position (Bcf) | 30.3 | 16.7 | 13.6 |

[1] Net of storage fees of $4.2 million and $3.8 million.

Results for our nonregulated operations during the third fiscal quarter continue to be adversely influenced by unfavorable natural gas market conditions. Historically high natural gas storage levels caused by strong domestic natural gas production caused natural gas prices to remain relatively low during our fiscal third quarter. Additionally, we continue to experience compressed spot to forward spread values and basis differentials.

We anticipate these natural gas market conditions will continue for the foreseeable future. As a result, we anticipate that basis differentials will remain compressed and spot-to-forward price volatility will remain relatively low. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be lower than in previous years for the foreseeable future.

Realized margins for gas delivery, storage and transportation services and other services were $13.7 million during the three months ended June 30, 2012 compared with $16.9 million for the prior-year quarter. The decrease primarily reflects a 10 percent decrease in consolidated sales volumes due to lower demand from industrial customers and lower deliveries to power generation customers due to milder weather compared to the prior-year quarter.

Asset optimization margins increased $18.2 million from the prior-year quarter primarily due to realized gains earned from AEM's trading strategy executed earlier in the fiscal year. During the first six months of fiscal 2012, AEM took advantage of falling natural gas prices by injecting gas into storage and rolling financial positions scheduled to settle during the third and fourth fiscal quarters of fiscal 2012. These gains were partially offset by increased storage fees associated with increased park and loan activity.

The $2.9 million increase in unrealized margins primarily reflects the impact of falling prices on our physical inventory as this hedged inventory is marked to market.

In the prior-year quarter we recorded an $11.0 million asset impairment charge related to our investment in certain natural gas gathering assets.

*Nine Months Ended June 30, 2012 compared with Nine Months Ended June 30, 2011*

Financial and operational highlights for our nonregulated segment for the nine months ended June 30, 2012 and 2011 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 35,021 | $ 46,842 | $(11,821) |
| Storage and transportation services | 9,953 | 10,913 | (960) |
| Other | 2,804 | 3,956 | (1,152) |
| | 47,778 | 61,711 | (13,933) |
| Asset optimization[(1)] | (17,039) | (344) | (16,695) |
| **Total realized margins** | 30,739 | 61,367 | (30,628) |
| **Unrealized margins** | 11,858 | (2,726) | 14,584 |
| **Gross profit** | 42,597 | 58,641 | (16,044) |
| Operating expenses, excluding asset impairments | 24,457 | 30,200 | (5,743) |
| Asset impairments | — | 30,270 | (30,270) |
| **Operating income (loss)** | 18,140 | (1,829) | 19,969 |
| Miscellaneous income | 739 | 764 | (25) |
| Interest charges | 1,686 | 1,759 | (73) |
| **Income (loss) before income taxes** | 17,193 | (2,824) | 20,017 |
| Income tax expense (benefit) | 6,958 | (1,364) | 8,322 |
| **Net income (loss)** | $ 10,235 | $ (1,460) | $ 11,695 |
| Gross nonregulated delivered gas sales volumes — MMcf | 307,800 | 339,747 | (31,947) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 270,372 | 290,486 | (20,114) |
| Net physical position (Bcf) | 30.3 | 16.7 | 13.6 |

(1) Net of storage fees of $13.7 million and $10.7 million.

Realized margins for gas delivery, storage and transportation services and other services were $47.8 million during the nine months ended June 30, 2012 compared with $61.7 million for the prior-year period. The decrease reflects the following:

- A seven percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A decrease in gas delivery per-unit margins from $0.14/Mcf in the prior-year period to $0.11/Mcf in the current-year period primarily due to lower basis differentials resulting from increased natural gas supply and increased transportation costs. The decrease in basis differentials was partially offset by increased fees earned from certain transportation arrangements and the receipt of a one-time refund of transportation demand fees from one of our transporters.

Asset optimization margins decreased $16.7 million from the prior-year period. The period-over-period decrease primarily reflects AEH's decision during the first six months of fiscal 2012 to take advantage of falling natural gas prices by purchasing and injecting gas into storage and rolling financial positions scheduled to settle during the third and fourth quarter of fiscal 2012. As a result of this decision and falling prices, we realized significantly higher losses on the settlement of financial instruments used to hedge our natural gas purchases during the first two quarters of fiscal 2012.

Additionally, AEH experienced increased storage fees associated with increased park and loan activity. Finally, AEH incurred a $1.7 million charge in the first fiscal quarter to write down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Unrealized margins increased $14.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses, excluding asset impairments decreased $5.7 million primarily due to lower employee-related expenses. Asset impairments include the aforementioned pre-tax impairment charge recorded in the prior-year period related to the write-off of certain natural gas gathering assets as well as an asset impairment charge of $19.3 million recorded in March 2011 related to our investment in our Fort Necessity storage project.

**Liquidity and Capital Resources**

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

As discussed in Note 6, our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On July 27, 2012 we issued a notice of early redemption of these notes on August 28, 2012. We intend to initially fund the redemption through the issuance of commercial paper. Shortly thereafter, we intend to enter into a short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received from the issuance of new unsecured notes anticipated to occur in January 2013. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2012.

**Cash Flows**

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the nine months ended June 30, 2012 and 2011 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | | (In thousands) | |
| Total cash provided by (used in) | | | |
| Operating activities | $ 518,806 | $ 519,562 | $ (756) |
| Investing activities | (501,621) | (393,656) | (107,965) |
| Financing activities | (120,898) | (140,429) | 19,531 |
| Change in cash and cash equivalents | (103,713) | (14,523) | (89,190) |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 | (533) |
| Cash and cash equivalents at end of period | $ 27,706 | $ 117,429 | $ (89,723) |

*Cash flows from operating activities*

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and working capital changes, particularly within our natural gas distribution segment resulting from 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, 2012, we generated operating cash flow of $518.8 million from operating activities compared with $519.6 million for the nine months ended June 30, 2011. The $0.8 million decrease in operating cash flows primarily reflects the $46.6 million increase in contributions made to our pension and postretirement plans during the first nine months of fiscal 2012, offset by changes in working capital.

*Cash flows from investing activities*

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

Capital expenditures for fiscal 2012 are currently expected to range from $690 million to $710 million. For the nine months ended June 30, 2012, capital expenditures were $497.4 million compared with $390.3 million for the nine months ended June 30, 2011. The $107.1 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and other infrastructure replacement projects in our Mid-Tex, West Texas and Kentucky service areas, the development of new customer billing and information systems for our natural gas distribution segment and increased capital spending to increase the capacity on our Atmos Pipeline – Texas system.

*Cash flows from financing activities*

For the nine months ended June 30, 2012, our financing activities used $120.9 million of cash compared with $140.4 million of cash used in the prior-year period, primarily due to lower cash outflows associated with our short-term and long-term debt instruments, as follows:

- $125.4 million for short-term debt repayments. In the current-year period, $6.7 million of short-term debt was repaid, compared with $132.1 million in the prior-year period.

- $357.7 million for scheduled long-term debt repayments. In the current-year period, $2.4 million of long-term debt was repaid, compared with $360.1 million in the prior-year period.

The lower repayment activity was partially offset by:

- $394.6 million and $20.1 million less cash received related to the issuance of long-term debt and the related settlement of Treasury locks in the prior year.
- $27.8 million less cash received related to the unwinding of two Treasury locks in the prior year.
- $12.5 million additional cash used to repurchase common stock as part of our share buyback program.
- $7.3 million less cash received from proceeds related to the issuance of common stock.

The following table summarizes our share issuances for the nine months ended June 30, 2012 and 2011.

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2012 | 2011 |
| Shares issued: | | |
| 1998 Long-Term Incentive Plan | 414,778 | 663,555 |
| Outside Directors Stock-for-Fee Plan | 1,823 | 1,801 |
| Total shares issued | 416,601 | 665,356 |

The year-over-year decrease in the number of shares issued primarily reflects the significant number of stock options exercised in the prior year. During the current-year period, we cancelled and retired 152,427 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares through our 2011 share repurchase program described in Note 7.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our 1998 Long-Term Incentive Plan (LTIP). In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

**Credit Facilities**

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

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program under our $750 million unsecured five-year credit facility and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of June 30, 2012, the amount available to us under our credit facilities, net of outstanding letters of credit, was $658.6 million.

**Shelf Registration**

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At June 30, 2012, $900 million was available for issuance. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires in March 2013.

### Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of June 30, 2012, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Unsecured senior long-term debt | BBB+ | Baa1 | A- |
| Commercial paper | A-2 | P-2 | F-2 |

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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

### Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2012. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

### Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2012, September 30, 2011 and June 30, 2011:

| | June 30, 2012 | | September 30, 2011 | | June 30, 2011 | |
|---|---|---|---|---|---|---|
| | (In thousands, except percentages) | | | | | |
| Short-term debt | $ 213,491 | 4.5% | $ 206,396 | 4.4% | $ — | — |
| Long-term debt | 2,206,420 | 46.2% | 2,208,551 | 47.3% | 2,208,540 | 48.6% |
| Shareholders' equity | 2,354,925 | 49.3% | 2,255,421 | 48.3% | 2,335,824 | 51.4% |
| Total | $4,774,836 | 100.0% | $4,670,368 | 100.0% | $4,544,364 | 100.0% |

Total debt as a percentage of total capitalization, including short-term debt, was 50.7 percent at June 30, 2012, 51.7 percent at September 30, 2011 and 48.6 percent at June 30, 2011. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

**Contractual Obligations and Commercial Commitments**

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2012.

**Risk Management Activities**

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and nine months ended June 30, 2012 and 2011:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $(47,532) | $ 30,533 | $(79,277) | $(49,600) |
| Contracts realized/settled | (351) | (13) | (31,888) | (51,058) |
| Fair value of new contracts | 1,251 | 1,801 | 874 | 2,872 |
| Other changes in value | (46,227) | (34,845) | 17,432 | 95,262 |
| Fair value of contracts at end of period | $(92,859) | $ (2,524) | $(92,859) | $ (2,524) |

The fair value of our natural gas distribution segment's financial instruments at June 30, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at June 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(94,066) | $1,207 | $— | $— | $(92,859) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(94,066) | $1,207 | $— | $— | $(92,859) |

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2012 and 2011:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $(2,574) | $(12,942) | $(25,050) | $(12,374) |
| Contracts realized/settled | (7,066) | 3,357 | 24,162 | 3,282 |
| Fair value of new contracts | — | — | — | — |
| Other changes in value | 5,080 | (1,824) | (3,672) | (2,317) |
| Fair value of contracts at end of period | (4,560) | (11,409) | (4,560) | (11,409) |
| Netting of cash collateral | 5,684 | 15,382 | 5,684 | 15,382 |
| Cash collateral and fair value of contracts at period end | $ 1,124 | $ 3,973 | $ 1,124 | $ 3,973 |

The fair value of our nonregulated segment's financial instruments at June 30, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at June 30, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(6,403) | $1,859 | $(16) | $— | $(4,560) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(6,403) | $1,859 | $(16) | $— | $(4,560) |

**Pension and Postretirement Benefits Obligations**

For the nine months ended June 30, 2012 and 2011, our total net periodic pension and other benefits costs were $51.9 million and $42.7 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2012 pension and postretirement medical costs for the nine months ended June 30, 2012 were higher than the prior-year period.

The amounts we fund our defined benefit plans with are determined in accordance with the PPA and are influenced by the discount rate and funded position of the plans when the funding requirements are determined on January 1 of each year. We completed our valuation for fiscal 2012 during the second fiscal quarter and as a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our qualified pension liabilities, we were required to contribute $23.0 million to the plans. During the nine months ended June 30, 2012, we contributed $40.3 million to our defined benefit plans and we anticipate contributing approximately $6 million during the remainder of the fiscal year. Additionally, we contributed $15.4 million to our postretirement medical plans during the nine months ended June 30, 2012 and anticipate contributing between $5 million and $10 million to these plans during the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

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

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and nine month periods ended June 30, 2012 and 2011.

*Natural Gas Distribution Sales and Statistical Data — Continuing Operations*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| **METERS IN SERVICE, end of period** | | | | |
| Residential | 2,851,606 | 2,845,554 | 2,851,606 | 2,845,554 |
| Commercial | 259,498 | 258,448 | 259,498 | 258,448 |
| Industrial | 2,250 | 2,319 | 2,250 | 2,319 |
| Public authority and other | 10,239 | 10,206 | 10,239 | 10,206 |
| Total meters | 3,123,593 | 3,116,527 | 3,123,593 | 3,116,527 |
| **INVENTORY STORAGE BALANCE — Bcf** | 38.6 | 36.3 | 38.6 | 36.3 |
| **SALES VOLUMES — MMcf** [2] | | | | |
| Gas sales volumes | | | | |
| Residential | 14,555 | 17,077 | 128,157 | 150,154 |
| Commercial | 13,684 | 14,149 | 71,955 | 79,632 |
| Industrial | 3,508 | 3,922 | 13,617 | 15,115 |
| Public authority and other | 1,660 | 1,863 | 7,737 | 8,764 |
| Total gas sales volumes | 33,407 | 37,011 | 221,466 | 253,665 |
| Transportation volumes | 31,384 | 31,036 | 103,420 | 102,824 |
| Total throughput | 64,791 | 68,047 | 324,886 | 356,489 |
| **OPERATING REVENUES (000's)**[2] | | | | |
| Gas sales revenues | | | | |
| Residential | $ 190,773 | $ 232,725 | $1,217,390 | $1,379,223 |
| Commercial | 94,137 | 118,916 | 513,029 | 593,860 |
| Industrial | 13,669 | 22,525 | 65,524 | 85,641 |
| Public authority and other | 7,551 | 12,013 | 46,794 | 58,096 |
| Total gas sales revenues | 306,130 | 386,179 | 1,842,737 | 2,116,820 |
| Transportation revenues | 13,288 | 13,946 | 44,017 | 47,364 |
| Other gas revenues | 5,633 | 6,906 | 20,597 | 23,723 |
| Total operating revenues | $ 325,051 | $ 407,031 | $1,907,351 | $2,187,907 |
| Average transportation revenue per Mcf[1] | $ 0.43 | $ 0.45 | $ 0.43 | $ 0.46 |
| Average cost of gas per Mcf sold[1] | $ 3.73 | $ 5.59 | $ 4.70 | $ 5.21 |

See footnote following these tables.

*Natural Gas Distribution Sales and Statistical Data — Discontinued Operations*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Meters in service, end of period | 82,687 | 83,109 | 82,687 | 83,109 |
| Inventory storage balance — Bcf | 1.7 | 2.0 | 1.7 | 2.0 |
| Sales volumes — MMcf | | | | |
| Total gas sales volumes | 698 | 936 | 6,221 | 7,910 |
| Transportation volumes | 1,283 | 1,192 | 4,634 | 4,813 |
| Total throughput | 1,981 | 2,128 | 10,855 | 12,723 |
| Operating revenues (000's) | $ 8,745 | $11,524 | $58,570 | $71,047 |

*Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| **CUSTOMERS, end of period** | | | | |
| Industrial | 797 | 764 | 797 | 764 |
| Municipal | 141 | 61 | 141 | 61 |
| Other | 433 | 511 | 433 | 511 |
| Total | 1,371 | 1,336 | 1,371 | 1,336 |
| **NONREGULATED INVENTORY STORAGE BALANCE — Bcf** | 33.3 | 21.4 | 33.3 | 21.4 |
| **REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf** (2) | 146,170 | 141,294 | 483,360 | 468,943 |
| **NONREGULATED DELIVERED GAS SALES VOLUMES —MMcf**(2) | 89,682 | 104,658 | 307,800 | 339,747 |
| **OPERATING REVENUES (000's)** (2) | | | | |
| Regulated transmission and storage | $ 67,073 | $ 53,570 | $ 181,869 | $ 157,553 |
| Nonregulated | 256,250 | 491,285 | 1,071,189 | 1,550,456 |
| Total operating revenues | $323,323 | $544,855 | $1,253,058 | $1,708,009 |

Notes to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

## RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the nine months ended June 30, 2012, there were no material changes in our quantitative and qualitative disclosures about market risk.

## Item 4. *Controls and Procedures*

### Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

# PART II. OTHER INFORMATION

## Item 1. *Legal Proceedings*

During the nine months ended June 30, 2012, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

## Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. We did not repurchase any shares during the third quarter of fiscal 2012. At June 30, 2012, there were 4,612,009 shares of repurchase authority remaining under the program.

## Item 6. *Exhibits*

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

## SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: August 9, 2012

## EXHIBITS INDEX
### Item 6

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 12 | Computation of ratio of earnings to fixed charges | |
| 15 | Letter regarding unaudited interim financial information | |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications* | |
| 101.INS | XBRL Instance Document | |
| 101.SCH | XBRL Taxonomy Extension Schema | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase | |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase | |

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

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

# Form 10-Q

(Mark One)

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

**For the quarterly period ended March 31, 2012**

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 27, 2012.

| Class | Shares Outstanding |
|---|---|
| No Par Value | 90,030,471 |

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AOCI | Accumulated other comprehensive income |
| APS | Atmos Pipeline and Storage, LLC |
| Bcf | Billion cubic feet |
| CFTC | Commodity Futures Trading Commission |
| FASB | Financial Accounting Standards Board |
| Fitch | Fitch Ratings, Ltd. |
| GRIP | Gas Reliability Infrastructure Program |
| GSRS | Gas System Reliability Surcharge |
| ISRS | Infrastructure System Replacement Surcharge |
| Mcf | Thousand cubic feet |
| MMcf | Million cubic feet |
| Moody's | Moody's Investors Services, Inc. |
| NYMEX | New York Mercantile Exchange, Inc. |
| PPA | Pension Protection Act of 2006 |
| PRP | Pipeline Replacement Program |
| RRC | Railroad Commission of Texas |
| RRM | Rate Review Mechanism |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| WNA | Weather Normalization Adjustment |

## PART I. FINANCIAL INFORMATION

**Item 1.** ***Financial Statements***

### ATMOS ENERGY CORPORATION

### CONDENSED CONSOLIDATED BALANCE SHEETS

| | March 31, 2012 | September 30, 2011 |
|---|---|---|
| | (Unaudited) | |
| | (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $6,992,899 | $6,816,794 |
| Less accumulated depreciation and amortization | 1,658,887 | 1,668,876 |
| Net property, plant and equipment | 5,334,012 | 5,147,918 |
| Current assets | | |
| Cash and cash equivalents | 47,040 | 131,419 |
| Accounts receivable, net | 350,261 | 273,303 |
| Gas stored underground | 221,112 | 289,760 |
| Other current assets | 275,428 | 316,471 |
| Total current assets | 893,841 | 1,010,953 |
| Goodwill and intangible assets | 740,185 | 740,207 |
| Deferred charges and other assets | 400,689 | 383,793 |
| | $7,368,727 | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2012 — 90,029,852 shares; September 30, 2011 — 90,296,482 shares | $ 450 | $ 451 |
| Additional paid-in capital | 1,728,150 | 1,732,935 |
| Retained earnings | 685,206 | 570,495 |
| Accumulated other comprehensive loss | (53,094) | (48,460) |
| Shareholders' equity | 2,360,712 | 2,255,421 |
| Long-term debt | 1,956,213 | 2,206,117 |
| Total capitalization | 4,316,925 | 4,461,538 |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 309,864 | 291,205 |
| Other current liabilities | 374,123 | 367,563 |
| Short-term debt | 173,996 | 206,396 |
| Current maturities of long-term debt | 250,131 | 2,434 |
| Total current liabilities | 1,108,114 | 867,598 |
| Deferred income taxes | 1,062,488 | 960,093 |
| Regulatory cost of removal obligation | 414,001 | 428,947 |
| Deferred credits and other liabilities | 467,199 | 564,695 |
| | $7,368,727 | $7,282,871 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Three Months Ended March 31 2012 | Three Months Ended March 31 2011 |
|---|---|---|
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $ 889,008 | $1,077,414 |
| Regulated transmission and storage segment | 58,037 | 54,976 |
| Nonregulated segment | 370,763 | 583,531 |
| Intersegment eliminations | (74,358) | (134,424) |
| | 1,243,450 | 1,581,497 |
| Purchased gas cost | | |
| Natural gas distribution segment | 508,206 | 698,410 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 374,992 | 563,473 |
| Intersegment eliminations | (74,009) | (134,054) |
| | 809,189 | 1,127,829 |
| Gross profit | 434,261 | 453,668 |
| Operating expenses | | |
| Operation and maintenance | 110,708 | 114,162 |
| Depreciation and amortization | 60,272 | 55,467 |
| Taxes, other than income | 54,919 | 53,558 |
| Asset impairment | — | 19,282 |
| Total operating expenses | 225,899 | 242,469 |
| Operating income | 208,362 | 211,199 |
| Miscellaneous income | 616 | 26,202 |
| Interest charges | 36,660 | 37,875 |
| Income from continuing operations before income taxes | 172,318 | 199,526 |
| Income tax expense | 66,408 | 71,366 |
| Income from continuing operations | 105,910 | 128,160 |
| Income from discontinued operations, net of tax ($1,834 and $2,642) | 3,201 | 4,049 |
| Net income | $ 109,111 | $ 132,209 |
| Basic earnings per share | | |
| Income per share from continuing operations | $ 1.16 | $ 1.41 |
| Income per share from discontinued operations | 0.04 | 0.04 |
| Net income per share — basic | $ 1.20 | $ 1.45 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 1.16 | $ 1.41 |
| Income per share from discontinued operations | 0.04 | 0.04 |
| Net income per share — diluted | $ 1.20 | $ 1.45 |
| Cash dividends per share | $ 0.345 | $ 0.340 |
| Weighted average shares outstanding: | | |
| Basic | 90,020 | 90,246 |
| Diluted | 90,322 | 90,533 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Six Months Ended March 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $1,582,300 | $1,780,876 |
| Regulated transmission and storage segment | 114,796 | 103,983 |
| Nonregulated segment | 814,939 | 1,059,171 |
| Intersegment eliminations | (167,412) | (229,271) |
| | 2,344,623 | 2,714,759 |
| Purchased gas cost | | |
| Natural gas distribution segment | 910,413 | 1,110,936 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 803,763 | 1,013,935 |
| Intersegment eliminations | (166,696) | (228,504) |
| | 1,547,480 | 1,896,367 |
| Gross profit | 797,143 | 818,392 |
| Operating expenses | | |
| Operation and maintenance | 226,770 | 228,652 |
| Depreciation and amortization | 119,487 | 110,244 |
| Taxes, other than income | 98,117 | 93,726 |
| Asset impairment | — | 19,282 |
| Total operating expenses | 444,374 | 451,904 |
| Operating income | 352,769 | 366,488 |
| Miscellaneous income (expense) | (1,259) | 25,476 |
| Interest charges | 72,102 | 76,770 |
| Income from continuing operations before income taxes | 279,408 | 315,194 |
| Income tax expense | 107,710 | 115,934 |
| Income from continuing operations | 171,698 | 199,260 |
| Income from discontinued operations, net of tax ($3,393 and $4,532) | 5,920 | 6,946 |
| Net income | $ 177,618 | $ 206,206 |
| Basic earnings per share | | |
| Income per share from continuing operations | $ 1.89 | $ 2.18 |
| Income per share from discontinued operations | 0.06 | 0.08 |
| Net income per share — basic | $ 1.95 | $ 2.26 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 1.88 | $ 2.18 |
| Income per share from discontinued operations | 0.06 | 0.08 |
| Net income per share — diluted | $ 1.94 | $ 2.26 |
| Cash dividends per share | $ 0.690 | $ 0.680 |
| Weighted average shares outstanding: | | |
| Basic | 90,137 | 90,157 |
| Diluted | 90,440 | 90,455 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Six Months Ended March 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (Unaudited) (In thousands) | |
| Cash Flows From Operating Activities | | |
| Net income | $ 177,618 | $ 206,206 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Asset impairment | — | 19,282 |
| Depreciation and amortization: | | |
| Charged to depreciation and amortization | 122,532 | 113,297 |
| Charged to other accounts | 203 | 98 |
| Deferred income taxes | 102,052 | 115,302 |
| Other | 9,874 | 10,255 |
| Net assets / liabilities from risk management activities | 15,690 | (17,478) |
| Net change in operating assets and liabilities | (67,246) | (8,491) |
| Net cash provided by operating activities | 360,723 | 438,471 |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (311,123) | (246,663) |
| Other, net | (3,878) | (1,535) |
| Net cash used in investing activities | (315,001) | (248,198) |
| Cash Flows From Financing Activities | | |
| Net decrease in short-term debt | (48,945) | (128,884) |
| Unwinding of Treasury lock agreements | — | 27,803 |
| Repayment of long-term debt | (2,369) | (10,066) |
| Cash dividends paid | (62,907) | (62,067) |
| Repurchase of common stock | (12,535) | — |
| Repurchase of equity awards | (3,509) | (3,333) |
| Issuance of common stock | 164 | 7,568 |
| Net cash used in financing activities | (130,101) | (168,979) |
| Net increase (decrease) in cash and cash equivalents | (84,379) | 21,294 |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 |
| Cash and cash equivalents at end of period | $ 47,040 | $ 153,246 |

See accompanying notes to condensed consolidated financial statements.

## ATMOS ENERGY CORPORATION

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
**(Unaudited)**
**March 31, 2012**

### 1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which currently cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

We operate the Company through the following three segments:

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

### 2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2012 are not indicative of our results of operations for the full 2012 fiscal year, which ends September 30, 2012.

We have evaluated subsequent events from the March 31, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as discussed in Note 6, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

***Significant accounting policies***

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011.

Due to the pending sale of our distribution operations in our Missouri, Illinois and Iowa service areas, the financial results for these service areas are shown in discontinued operations. Accordingly, certain prior-year amounts have been reclassified to conform with the current year presentation.

During the second quarter of fiscal 2012, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the six months ended March 31, 2012, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard indefinitely defers the effective date for amendments to the presentation of reclassifications of items out of accumulated other comprehensive income as prescribed by a previously issued standard, which were initially to be effective for interim and annual periods beginning after December 15, 2011. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the six months ended March 31, 2012.

***Regulatory assets and liabilities***

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of March 31, 2012 and September 30, 2011 included the following:

| | March 31, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| **Regulatory assets:** | | |
| Pension and postretirement benefit costs | $245,096 | $254,666 |
| Merger and integration costs, net | 5,998 | 6,242 |
| Deferred gas costs | 19,547 | 33,976 |
| Regulatory cost of removal asset | 10,233 | 8,852 |
| Environmental costs | 117 | 385 |
| Rate case costs | 4,503 | 4,862 |
| Deferred franchise fees | 333 | 379 |
| Other | 8,861 | 3,534 |
| | $294,688 | $312,896 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 15,232 | $ 8,130 |
| Regulatory cost of removal obligation | 463,740 | 464,025 |
| Other | 13,090 | 14,025 |
| | $492,062 | $486,180 |

The amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of March 31, 2012, we had deferred $0.7 million associated with the requirements of this rule which are recorded in "Other" in the regulatory assets table above.

Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. During the quarter, we elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $2.5 million, which is recorded in "Other" in the regulatory assets table above. Of this amount, $1.4 million represented a reduction to operation and maintenance expense during the second quarter of fiscal 2012.

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

***Comprehensive income***

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and six-month periods ended March 31, 2012 and 2011:

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Net income | $109,111 | $132,209 | $177,618 | $206,206 |
| Unrealized holding gains on investments, net of tax expense of $1,203 and $477 for the three months ended March 31, 2012 and 2011 and of $1,717 and $932 for the six months ended March 31, 2012 and 2011 | 2,046 | 810 | 2,947 | 1,586 |
| Amortization, unrealized gain and unwinding of treasury lock agreements, net of tax expense (benefit) of $9,042 and $(6,125) for the three months ended March 31, 2012 and 2011 and $8,404 and $12,579 for the six month ended March 31, 2012 and 2011 | 15,396 | (10,427) | 14,309 | 21,420 |
| Net unrealized gains (losses) on cash flow hedging transactions, net of tax expense (benefit) of $(3,399) and $2,573 for the three months ended March 31, 2012 and 2011 and $(13,996) and $9,190 for the six months ended March 31, 2012 and 2011 | (5,315) | 4,025 | (21,890) | 14,375 |
| Comprehensive income | $121,238 | $126,617 | $172,984 | $243,587 |

Accumulated other comprehensive income (loss), net of tax, as of March 31, 2012 and September 30, 2011 consisted of the following unrealized gains (losses):

| | March 31, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive income (loss): | | |
| Unrealized holding gains on investments | $ 5,505 | $ 2,558 |
| Treasury lock agreements | (19,848) | (34,157) |
| Cash flow hedges | (38,751) | (16,861) |
| | $(53,094) | $(48,460) |

## 3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

***Regulated Commodity Risk Management Activities***

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

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

***Nonregulated Commodity Risk Management Activities***

The primary business in our nonregulated operations is to aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. We utilize proprietary and customer-owned transportation and storage assets to serve these customers, and will seek to maximize the value of this storage capacity through the arbitrage of pricing differences that occur over time by selling financial instruments at advantageous prices to lock in a gross profit margin to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 56 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

### *Interest Rate Risk Management Activities*

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

As of March 31, 2012, we had three Treasury lock agreements outstanding to fix the Treasury yield component of 30-year unsecured notes, which we plan to issue to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

### *Quantitative Disclosures Related to Financial Instruments*

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

As of March 31, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

| Contract Type | Hedge Designation | Natural Gas Distribution | Nonregulated |
|---|---|---|---|
| | | Quantity (MMcf) | |
| Commodity contracts | Fair Value | — | (38,340) |
| | Cash Flow | — | 49,098 |
| | Not designated | 6,033 | 28,190 |
| | | 6,033 | 38,948 |

*Financial Instruments on the Balance Sheet*

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2012 and September 30, 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $5.7 million and $28.8 million of cash held on deposit in margin accounts as of March 31, 2012 and September 30, 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **March 31, 2012** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 77,441 | $ 77,441 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | — | — |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (45,818) | (59,301) | (105,119) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (10,914) | (10,914) |
| **Total** | | (45,818) | 7,226 | (38,592) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 502 | 137,934 | 138,436 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 85,951 | 85,951 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[(1)] | (2,215) | (164,189) | (166,404) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (1) | (69,496) | (69,497) |
| **Total** | | (1,714) | (9,800) | (11,514) |
| **Total Financial Instruments** | | $(47,532) | $ (2,574) | $ (50,106) |

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.8 million related to risk management liabilities that were classified as assets held for sale at March 31, 2012.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **September 30, 2011** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 22,396 | $ 22,396 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 174 | 174 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | — | (31,064) | (31,064) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (67,527) | (7,709) | (75,236) |
| **Total** | | (67,527) | (16,203) | (83,730) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 843 | 67,710 | 68,553 |
| Noncurrent commodity contracts | Deferred charges and other assets | 998 | 22,379 | 23,377 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[1] | (13,256) | (73,865) | (87,121) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (335) | (25,071) | (25,406) |
| **Total** | | (11,750) | (8,847) | (20,597) |
| **Total Financial Instruments** | | $(79,277) | $(25,050) | $(104,327) |

[1] Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

*Impact of Financial Instruments on the Income Statement*

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2012 and 2011 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(6.2) million and $4.1 million. For the six months ended March 31, 2012 and 2011 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $2.2 million and $17.5 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

*Fair Value Hedges*

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2012 and 2011 is presented below.

| | Three Months Ended March 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Commodity contracts | $ 29,090 | $(1,279) |
| Fair value adjustment for natural gas inventory designated as the hedged item | (35,087) | 5,586 |
| Total impact on revenue | $ (5,997) | $ 4,307 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ (739) | $ (509) |
| Timing ineffectiveness | (5,258) | 4,816 |
| | $ (5,997) | $ 4,307 |

| | Six Months Ended March 31 | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Commodity contracts | $ 53,153 | $ (3,003) |
| Fair value adjustment for natural gas inventory designated as the hedged item | (50,335) | 21,211 |
| Total impact on revenue | $ 2,818 | $18,208 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 102 | $ 412 |
| Timing ineffectiveness | 2,716 | 17,796 |
| | $ 2,818 | $18,208 |

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the six months ended March 31, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the six months ended March 31, 2011.

*Cash Flow Hedges*

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2012 and 2011 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | Three Months Ended March 31, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(21,181) | $(21,181) |
| Loss arising from ineffective portion of commodity contracts | — | — | (238) | (238) |
| Total impact on revenue | — | — | (21,419) | (21,419) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (502) | — | — | (502) |
| Total Impact from Cash Flow Hedges | $(502) | $ — | $(21,419) | $(21,921) |

| | Three Months Ended March 31, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(7,328) | $ (7,328) |
| Loss arising from ineffective portion of commodity contracts | — | — | (233) | (233) |
| Total impact on revenue | — | — | (7,561) | (7,561) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (669) | — | — | (669) |
| Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income | 21,803 | 6,000 | — | 27,803 |
| Total Impact from Cash Flow Hedges | $21,134 | $6,000 | $(7,561) | $19,573 |

| | Six Months Ended March 31, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(32,823) | $(32,823) |
| Loss arising from ineffective portion of commodity contracts | — | — | (668) | (668) |
| Total impact on revenue | — | — | (33,491) | (33,491) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (1,004) | — | — | (1,004) |
| Total Impact from Cash Flow Hedges | $(1,004) | $ — | $(33,491) | $(34,495) |

| | Six Months Ended March 31, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(21,581) | $(21,581) |
| Loss arising from ineffective portion of commodity contracts | — | — | (677) | (677) |
| Total impact on revenue | — | — | (22,258) | (22,258) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (1,339) | — | — | (1,339) |
| Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income | 21,803 | 6,000 | — | 27,803 |
| Total Impact from Cash Flow Hedges | $20,464 | $6,000 | $(22,258) | $ 4,206 |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| *Increase (decrease) in fair value:* | | | | |
| Treasury lock agreements | $ 15,079 | $ 6,667 | $ 13,676 | $ 38,092 |
| Forward commodity contracts | (18,234) | (446) | (41,912) | 1,211 |
| *Recognition of (gains) losses in earnings due to settlements:* | | | | |
| Treasury lock agreements | 317 | (17,094) | 633 | (16,672) |
| Forward commodity contracts | 12,919 | 4,471 | 20,022 | 13,164 |
| Total other comprehensive income (loss) from hedging, net of tax[1] | $ 10,081 | $ (6,402) | $ (7,581) | $ 35,795 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our treasury lock agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2012. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock agreements as these instruments have not yet settled.

| | Treasury Lock Agreements | Commodity Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| Next twelve months | $ (1,266) | $(32,130) | $(33,396) |
| Thereafter | 10,284 | (6,621) | 3,663 |
| Total[1] | $ 9,018 | $(38,751) | $(29,733) |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

*Financial Instruments Not Designated as Hedges*

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended March 31, 2012 and 2011 was an increase (decrease) in revenue of $(12.8) million and $4.0 million. For the six months ended March 31, 2012 and 2011 revenue increased (decreased) $(15.0) million and $8.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

### 4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three and six months ended March 31, 2012, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2011.

## Quantitative Disclosures

*Financial Instruments*

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2012 and September 30, 2011. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)(1) | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral(2) | March 31, 2012 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 502 | $ — | $ — | $ 502 |
| Nonregulated segment | 52,013 | 249,313 | — | (287,608) | 13,718 |
| Total financial instruments | 52,013 | 249,815 | — | (287,608) | 14,220 |
| Hedged portion of gas stored underground | 73,043 | — | — | — | 73,043 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 3,358 | — | — | 3,358 |
| Registered investment companies | 38,424 | — | — | — | 38,424 |
| Bonds | — | 23,637 | — | — | 23,637 |
| Total available-for-sale securities | 38,424 | 26,995 | — | — | 65,419 |
| Total assets | $163,480 | $276,810 | $ — | $(287,608) | $152,682 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 48,034 | $ — | $ — | $ 48,034 |
| Nonregulated segment | 76,476 | 227,424 | — | (293,304) | 10,596 |
| Total liabilities | $ 76,476 | $275,458 | $ — | $(293,304) | $ 58,630 |

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)(1) | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral(3) | September 30, 2011 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 1,841 | $ — | $ — | $ 1,841 |
| Nonregulated segment | 15,262 | 97,396 | — | (95,156) | 17,502 |
| Total financial instruments | 15,262 | 99,237 | — | (95,156) | 19,343 |
| Hedged portion of gas stored underground | 47,940 | — | — | — | 47,940 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 1,823 | — | — | 1,823 |
| Registered investment companies | 36,444 | — | — | — | 36,444 |
| Bonds | — | 14,366 | — | — | 14,366 |
| Total available-for-sale securities | 36,444 | 16,189 | — | — | 52,633 |
| Total assets | $99,646 | $115,426 | $ — | $ (95,156) | $119,916 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 81,118 | $ — | $ — | $ 81,118 |
| Nonregulated segment | 22,091 | 115,617 | — | (123,943) | 13,765 |
| Total liabilities | $22,091 | $196,735 | $ — | $(123,943) | $ 94,883 |

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of March 31, 2012, we had $5.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $2.8 million was used to offset current risk management liabilities under master netting arrangements and the remaining $2.9 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

| | Amortized Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| | | (In thousands) | | |
| **As of March 31, 2012:** | | | | |
| Domestic equity mutual funds | $24,471 | $7,821 | $ — | $32,292 |
| Foreign equity mutual funds | 5,327 | 805 | — | 6,132 |
| Bonds | 23,525 | 127 | (15) | 23,637 |
| Money market funds | 3,358 | — | — | 3,358 |
| | $56,681 | $8,753 | $ (15) | $65,419 |
| **As of September 30, 2011:** | | | | |
| Domestic equity mutual funds | $27,748 | $4,074 | $ — | $31,822 |
| Foreign equity mutual funds | 4,597 | 267 | (242) | 4,622 |
| Bonds | 14,390 | 10 | (34) | 14,366 |
| Money market funds | 1,823 | — | — | 1,823 |
| | $48,558 | $4,351 | $(276) | $52,633 |

At March 31, 2012 and September 30, 2011, our available-for-sale securities included $41.8 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2012 we maintained investments in bonds that have contractual maturity dates ranging from April 2012 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

We maintained several bonds with a cumulative fair value of $4.4 million in an unrealized loss position of less than $0.1 million as of March 31, 2012. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment grade, we do not consider this impairment to be other than temporary as of March 31, 2012.

*Other Fair Value Measures*

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of March 31, 2012:

| | March 31, 2012 |
|---|---|
| | (In thousands) |
| Carrying Amount | $2,210,196 |
| Fair Value | $2,583,071 |

## 5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur during fiscal 2012.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at March 31, 2012 and September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Operating revenues | $26,374 | $35,790 | $49,825 | $59,523 |
| Purchased gas cost | 17,026 | 24,636 | 31,977 | 39,533 |
| Gross profit | 9,348 | 11,154 | 17,848 | 19,990 |
| Operating expenses | 4,275 | 4,431 | 8,449 | 8,447 |
| Operating income | 5,073 | 6,723 | 9,399 | 11,543 |
| Other nonoperating expense | (38) | (32) | (86) | (65) |
| Income from discontinued operations before income taxes | 5,035 | 6,691 | 9,313 | 11,478 |
| Income tax expense | 1,834 | 2,642 | 3,393 | 4,532 |
| Net income | $ 3,201 | $ 4,049 | $ 5,920 | $ 6,946 |

The following table presents balance sheet data related to assets held for sale.

| | March 31, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Net plant, property & equipment | $126,587 | $127,577 |
| Gas stored underground | 6,517 | 11,931 |
| Other current assets | 515 | 786 |
| Deferred charges and other assets | 49 | 277 |
| Assets held for sale | $133,668 | $140,571 |
| Accounts payable and accrued liabilities | $ 5,404 | $ 1,917 |
| Other current liabilities | 6,857 | 4,877 |
| Regulatory cost of removal | 7,687 | 10,498 |
| Deferred credits and other liabilities | 872 | 1,153 |
| Liabilities held for sale | $ 20,820 | $ 18,445 |

## 6. Debt

The nature and terms of our debt instruments are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes in the terms of our debt instruments during the six months ended March 31, 2012.

### *Long-term debt*

Long-term debt at March 31, 2012 and September 30, 2011 consisted of the following:

| | March 31, 2012 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Unsecured 10% Notes, redeemed December 2011 | $ — | $ 2,303 |
| Unsecured 5.125% Senior Notes, due January 2013 | 250,000 | 250,000 |
| Unsecured 4.95% Senior Notes, due 2014 | 500,000 | 500,000 |
| Unsecured 6.35% Senior Notes, due 2017 | 250,000 | 250,000 |
| Unsecured 8.50% Senior Notes, due 2019 | 450,000 | 450,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Unsecured 5.50% Senior Notes, due 2041 | 400,000 | 400,000 |
| Medium term notes | | |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| Rental property term note due in installments through 2013 | 196 | 262 |
| Total long-term debt | 2,210,196 | 2,212,565 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | (3,852) | (4,014) |
| Current maturities | (250,131) | (2,434) |
| | $1,956,213 | $2,206,117 |

Our unsecured 10% notes were paid on their maturity date on December 31, 2011 and were not replaced. As noted above, our Unsecured 5.125% Senior Notes will mature in January 2013; accordingly, these have been classified within the current maturities of long-term debt.

***Short-term debt***

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

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $985 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At March 31, 2012 and September 30, 2011, there was $174.0 million and $206.4 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

***Regulated Operations***

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding, including a five-year $750 million unsecured facility, a $25 million unsecured facility and a $10 million revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.2 million at March 31, 2012. Our $25 million unsecured facility was renewed effective April 1, 2012. This facility bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin.

In addition to these third-party facilities, our regulated operations had a $350 million intercompany revolving credit facility with AEH. This facility was replaced on January 1, 2012 with a $500 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

***Nonregulated Operations***

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility, expiring in December 2013, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH. Due to outstanding letters of credit and various covenants, including covenants based on working capital, the amount available to AEM under this credit facility was $82.0 million at March 31, 2012.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

### *Shelf Registration*

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At March 31, 2012, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

### *Debt Covenants*

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2012, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 52 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

AEM is required by the financial covenants in its facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At March 31, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.97 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at March 31, 2012, AEM's net working capital was $105.9 million and its tangible net worth was $142.5 million.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

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

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

We were in compliance with all of our debt covenants as of March 31, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

## 7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under our 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and six months ended March 31, 2012 and 2011 are calculated as follows:

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share amounts) | | | |
| **Basic Earnings Per Share from continuing operations** | | | | |
| Income from continuing operations | $105,910 | $128,160 | $171,698 | $199,260 |
| Less: Income from continuing operations allocated to participating securities | 1,109 | 1,342 | 1,794 | 2,089 |
| Income from continuing operations available to common shareholders | $104,801 | $126,818 | $169,904 | $197,171 |
| Basic weighted average shares outstanding | 90,020 | 90,246 | 90,137 | 90,157 |
| Income from continuing operations per share — Basic | $ 1.16 | $ 1.41 | $ 1.89 | $ 2.18 |
| **Basic Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations | $ 3,201 | $ 4,049 | $ 5,920 | $ 6,946 |
| Less: Income from discontinued operations allocated to participating securities | 34 | 42 | 62 | 73 |
| Income from discontinued operations available to common shareholders | $ 3,167 | $ 4,007 | $ 5,858 | $ 6,873 |
| Basic weighted average shares outstanding | 90,020 | 90,246 | 90,137 | 90,157 |
| Income from discontinued operations per share — Basic | $ 0.04 | $ 0.04 | $ 0.06 | $ 0.08 |
| Net income per share — Basic | $ 1.20 | $ 1.45 | $ 1.95 | $ 2.26 |

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share amounts) | | | |
| **Diluted Earnings Per Share from continuing operations** | | | | |
| Income from continuing operations available to common shareholders | $104,801 | $126,818 | $169,904 | $197,171 |
| Effect of dilutive stock options and other shares | 3 | 3 | 4 | 5 |
| Income from continuing operations available to common shareholders | $104,804 | $126,821 | $169,908 | $197,176 |
| Basic weighted average shares outstanding | 90,020 | 90,246 | 90,137 | 90,157 |
| Additional dilutive stock options and other shares | 302 | 287 | 303 | 298 |
| Diluted weighted average shares outstanding | 90,322 | 90,533 | 90,440 | 90,455 |
| Income from continuing operations per share — Diluted | $ 1.16 | $ 1.41 | $ 1.88 | $ 2.18 |
| **Diluted Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations available to common shareholders | $ 3,167 | $ 4,007 | $ 5,858 | $ 6,873 |
| Effect of dilutive stock options and other shares | — | — | — | — |
| Income from discontinued operations available to common shareholders | $ 3,167 | $ 4,007 | $ 5,858 | $ 6,873 |
| Basic weighted average shares outstanding | 90,020 | 90,246 | 90,137 | 90,157 |
| Additional dilutive stock options and other shares | 302 | 287 | 303 | 298 |
| Diluted weighted average shares outstanding | 90,322 | 90,533 | 90,440 | 90,455 |
| Income from discontinued operations per share — Diluted | $ 0.04 | $ 0.04 | $ 0.06 | $ 0.08 |
| Net income per share — Diluted | $ 1.20 | $ 1.45 | $ 1.94 | $ 2.26 |

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2012 and 2011 as their exercise price was less than the average market price of the common stock during that period.

***Share Repurchase Program***

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. However, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of March 31, 2012, 387,991 shares had been repurchased for an aggregate value of $12.5 million.

## 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 and six months ended March 31, 2012 and 2011 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

| | Three Months Ended March 31 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 4,298 | $ 4,257 | $4,088 | $3,601 |
| Interest cost | 6,678 | 7,055 | 3,466 | 3,203 |
| Expected return on assets | (5,369) | (6,285) | (652) | (682) |
| Amortization of transition asset | — | — | 378 | 378 |
| Amortization of prior service cost | (36) | (105) | (363) | (363) |
| Amortization of actuarial loss | 4,143 | 2,748 | 662 | 86 |
| Curtailment gain | — | (40) | — | — |
| Net periodic pension cost | $ 9,714 | $ 7,630 | $7,579 | $6,223 |

| | Six Months Ended March 31 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 8,596 | $ 8,637 | $ 8,176 | $ 7,202 |
| Interest cost | 13,355 | 13,979 | 6,931 | 6,406 |
| Expected return on assets | (10,737) | (12,248) | (1,304) | (1,364) |
| Amortization of transition asset | — | — | 756 | 756 |
| Amortization of prior service cost | (71) | (217) | (725) | (725) |
| Amortization of actuarial loss | 8,285 | 6,242 | 1,324 | 173 |
| Curtailment gain | — | (40) | — | — |
| Net periodic pension cost | $ 19,428 | $ 16,353 | $15,158 | $12,448 |

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2012 and 2011 are as follows:

| | Pension Account Plan | | Other Pension Benefits | | Other Benefits | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Discount rate | 5.05% | 5.68% | 5.05% | 5.39% | 5.05% | 5.39% |
| Rate of compensation increase | 3.50% | 4.00% | 3.50% | 4.00% | N/A | N/A |
| Expected return on plan assets | 7.75% | 8.25% | 7.75% | 8.25% | 4.70% | 5.00% |

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid.

Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based upon this valuation, we contributed $23.0 million to our defined benefit pension plans during the second fiscal quarter to achieve a desirable PPA funding threshold. The need for this funding reflects the increased pension benefit obligation due to a decrease in the discount rate compared to the prior year as well as a decline in the fair value of plan assets. During the first six months of fiscal 2012, we contributed $34.2 million to our defined benefit plans and we anticipate contributing an additional $12.4 million during the remainder of the fiscal year.

We contributed $9.1 million to our other post-retirement benefit plans during the six months ended March 31, 2012. We expect to contribute a total of approximately $10 million to $15 million to these plans during the remainder of the fiscal year.

## 9. Commitments and Contingencies

***Litigation and Environmental Matters***

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2012.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky, *Billy Joe Honeycutt et al. vs. Atmos Energy Corporation, et al.*, which is related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

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

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

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter. However, we continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

***Purchase Commitments***

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2012, AEH was committed to purchase 96.2 Bcf within one year, 23.5 Bcf within one to three years and 0.6 Bcf after three years under indexed contracts. AEH is committed to purchase 3.5 Bcf within one year and 0.6 Bcf within one to three years under fixed price contracts with prices ranging from $1.75 to $6.36 per Mcf. Purchases under these contracts totaled $264.3 million and $438.9 million for the three months ended March 31, 2012 and 2011 and $576.4 million and $773.1 million for the six months ended March 31, 2012 and 2011.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of March 31, 2012 are as follows (in thousands):

| | |
|---|---|
| 2012 | $ 33,347 |
| 2013 | 71,496 |
| 2014 | 61,594 |
| 2015 | — |
| 2016 | — |
| Thereafter | — |
| | $166,437 |

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our

Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2012.

***Regulatory Matters***

As previously described in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. Since that time, we have fully cooperated with the Commission during this investigation.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

As discussed in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in 2010, our Mid-Tex Division agreed to install 100,000 steel service line replacements by September 30, 2012. As of March 31, 2012, we had replaced 73,822 lines and are on schedule for completion in September 2012. Under the terms of the agreement, special rate recovery of the associated return, depreciation and taxes is approved for lines replaced between October 1, 2010 and September 30, 2012. Since October 1, 2010, we have spent $81.4 million on steel service line replacements.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodity Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the SEC and CFTC have issued a number of rules and regulations, we expect additional rules and regulations to be issued, which should provide additional clarity regarding the extent of the impact of this legislation on the Company. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation and related rules and regulations. Additional reporting and disclosure obligations have been imposed upon the Company, the full extent of which will not be known until the SEC and the CFTC have completed their ongoing rulemaking process.

As of March 31, 2012, rate cases were in progress in our Mid-Tex, West Texas and Kansas service areas and annual rate filing mechanisms were in progress in our Mid-Tex and Louisiana service areas along with one infrastructure program filing in progress in our Atmos Pipeline — Texas service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

## 10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012, there were no material changes in our concentration of credit risk.

## 11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2012 and 2011 by segment are presented in the following tables:

| | Three Months Ended March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $888,685 | $20,430 | $334,335 | $ — | $1,243,450 |
| Intersegment revenues | 323 | 37,607 | 36,428 | (74,358) | — |
| | 889,008 | 58,037 | 370,763 | (74,358) | 1,243,450 |
| Purchased gas cost | 508,206 | — | 374,992 | (74,009) | 809,189 |
| Gross profit | 380,802 | 58,037 | (4,229) | (349) | 434,261 |
| Operating expenses | | | | | |
| Operation and maintenance | 89,443 | 15,847 | 5,769 | (351) | 110,708 |
| Depreciation and amortization | 51,755 | 7,792 | 725 | — | 60,272 |
| Taxes, other than income | 50,313 | 3,915 | 691 | — | 54,919 |
| Total operating expenses | 191,511 | 27,554 | 7,185 | (351) | 225,899 |
| Operating income (loss) | 189,291 | 30,483 | (11,414) | 2 | 208,362 |
| Miscellaneous income (expense) | 733 | (56) | 567 | (628) | 616 |
| Interest charges | 28,833 | 7,614 | 839 | (626) | 36,660 |
| Income (loss) from continuing operations before income taxes | 161,191 | 22,813 | (11,686) | — | 172,318 |
| Income tax expense (benefit) | 62,890 | 8,193 | (4,675) | — | 66,408 |
| Income (loss) from continuing operations | 98,301 | 14,620 | (7,011) | — | 105,910 |
| Income from discontinued operations, net of tax | 3,201 | — | — | — | 3,201 |
| Net income (loss) | $101,502 | $14,620 | $ (7,011) | $ — | $ 109,111 |
| Capital expenditures | $114,402 | $38,871 | $ 3,456 | $ — | $ 156,729 |

| | Three Months Ended March 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $1,077,178 | $21,597 | $482,722 | $ — | $1,581,497 |
| Intersegment revenues | 236 | 33,379 | 100,809 | (134,424) | — |
| | 1,077,414 | 54,976 | 583,531 | (134,424) | 1,581,497 |
| Purchased gas cost | 698,410 | — | 563,473 | (134,054) | 1,127,829 |
| Gross profit | 379,004 | 54,976 | 20,058 | (370) | 453,668 |
| Operating expenses | | | | | |
| Operation and maintenance | 92,266 | 15,231 | 7,035 | (370) | 114,162 |
| Depreciation and amortization | 48,555 | 5,798 | 1,114 | — | 55,467 |
| Taxes, other than income | 50,088 | 4,113 | (643) | — | 53,558 |
| Asset impairment | — | — | 19,282 | — | 19,282 |
| Total operating expenses | 190,909 | 25,142 | 26,788 | (370) | 242,469 |
| Operating income (loss) | 188,095 | 29,834 | (6,730) | — | 211,199 |
| Miscellaneous income | 20,156 | 5,861 | 306 | (121) | 26,202 |
| Interest charges | 29,605 | 8,085 | 306 | (121) | 37,875 |
| Income (loss) from continuing operations before income taxes | 178,646 | 27,610 | (6,730) | — | 199,526 |
| Income tax expense (benefit) | 64,085 | 9,871 | (2,590) | — | 71,366 |
| Income (loss) from continuing operations | 114,561 | 17,739 | (4,140) | — | 128,160 |
| Income from discontinued operations, net of tax | 4,049 | — | — | — | 4,049 |
| Net income (loss) | $ 118,610 | $17,739 | $ (4,140) | $ — | $ 132,209 |
| Capital expenditures | $ 109,762 | $11,818 | $ 1,921 | $ — | $ 123,501 |

| | Six Months Ended March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $1,581,753 | $ 39,870 | $723,000 | $ — | $2,344,623 |
| Intersegment revenues | 547 | 74,926 | 91,939 | (167,412) | — |
| | 1,582,300 | 114,796 | 814,939 | (167,412) | 2,344,623 |
| Purchased gas cost | 910,413 | — | 803,763 | (166,696) | 1,547,480 |
| Gross profit | 671,887 | 114,796 | 11,176 | (716) | 797,143 |
| Operating expenses | | | | | |
| Operation and maintenance | 182,857 | 32,812 | 11,820 | (719) | 226,770 |
| Depreciation and amortization | 102,586 | 15,443 | 1,458 | — | 119,487 |
| Taxes, other than income | 88,792 | 7,699 | 1,626 | — | 98,117 |
| Total operating expenses | 374,235 | 55,954 | 14,904 | (719) | 444,374 |
| Operating income (loss) | 297,652 | 58,842 | (3,728) | 3 | 352,769 |
| Miscellaneous income (expense) | (1,023) | (336) | 603 | (503) | (1,259) |
| Interest charges | 56,688 | 14,823 | 1,091 | (500) | 72,102 |
| Income (loss) from continuing operations before income taxes | 239,941 | 43,683 | (4,216) | — | 279,408 |
| Income tax expense (benefit) | 93,735 | 15,649 | (1,674) | — | 107,710 |
| Income (loss) from continuing operations | 146,206 | 28,034 | (2,542) | — | 171,698 |
| Income from discontinued operations, net of tax | 5,920 | — | — | — | 5,920 |
| Net income (loss) | $ 152,126 | $ 28,034 | $ (2,542) | $ — | $ 177,618 |
| Capital expenditures | $ 243,135 | $ 62,991 | $ 4,997 | $ — | $ 311,123 |

| | Six Months Ended March 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $1,780,439 | $ 42,830 | $ 891,490 | $ — | $2,714,759 |
| Intersegment revenues | 437 | 61,153 | 167,681 | (229,271) | — |
| | 1,780,876 | 103,983 | 1,059,171 | (229,271) | 2,714,759 |
| Purchased gas cost | 1,110,936 | — | 1,013,935 | (228,504) | 1,896,367 |
| Gross profit | 669,940 | 103,983 | 45,236 | (767) | 818,392 |
| Operating expenses | | | | | |
| Operation and maintenance | 181,495 | 30,805 | 17,119 | (767) | 228,652 |
| Depreciation and amortization | 96,449 | 11,597 | 2,198 | — | 110,244 |
| Taxes, other than income | 84,536 | 7,666 | 1,524 | — | 93,726 |
| Asset impairment | — | — | 19,282 | — | 19,282 |
| Total operating expenses | 362,480 | 50,068 | 40,123 | (767) | 451,904 |
| Operating income | 307,460 | 53,915 | 5,113 | — | 366,488 |
| Miscellaneous income | 19,458 | 5,579 | 596 | (157) | 25,476 |
| Interest charges | 59,302 | 16,149 | 1,476 | (157) | 76,770 |
| Income from continuing operations before income taxes | 267,616 | 43,345 | 4,233 | — | 315,194 |
| Income tax expense | 98,634 | 15,504 | 1,796 | — | 115,934 |
| Income from continuing operations | 168,982 | 27,841 | 2,437 | — | 199,260 |
| Income from discontinued operations, net of tax | 6,946 | — | — | — | 6,946 |
| Net income | $ 175,928 | $ 27,841 | $ 2,437 | $ — | $ 206,206 |
| Capital expenditures | $ 219,261 | $ 24,557 | $ 2,845 | $ — | $ 246,663 |

Balance sheet information at March 31, 2012 and September 30, 2011 by segment is presented to reflect our business structure as of March 31, 2012 in the following tables.

| | March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,382,291 | $ 886,507 | $ 65,214 | $ — | $5,334,012 |
| Investment in subsidiaries | 674,594 | — | (2,096) | (672,498) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 40,140 | — | 6,900 | — | 47,040 |
| Assets from risk management activities | 502 | — | 2,877 | — | 3,379 |
| Other current assets | 632,486 | 13,278 | 399,389 | (201,731) | 843,422 |
| Intercompany receivables | 584,018 | — | — | (584,018) | — |
| Total current assets | 1,257,146 | 13,278 | 409,166 | (785,749) | 893,841 |
| Intangible assets | — | — | 185 | — | 185 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | — | — | 10,841 | — | 10,841 |
| Deferred charges and other assets | 366,329 | 13,203 | 10,316 | — | 389,848 |
| | $7,253,268 | $1,045,369 | $528,337 | $(1,458,247) | $7,368,727 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,360,712 | $ 293,135 | $381,459 | $ (674,594) | $2,360,712 |
| Long-term debt | 1,956,147 | — | 66 | — | 1,956,213 |
| Total capitalization | 4,316,859 | 293,135 | 381,525 | (674,594) | 4,316,925 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 250,000 | — | 131 | — | 250,131 |
| Short-term debt | 371,996 | — | — | (198,000) | 173,996 |
| Liabilities from risk management activities | 47,281 | — | 5,296 | — | 52,577 |
| Other current liabilities | 507,354 | 6,309 | 119,382 | (1,635) | 631,410 |
| Intercompany payables | — | 551,330 | 32,688 | (584,018) | — |
| Total current liabilities | 1,176,631 | 557,639 | 157,497 | (783,653) | 1,108,114 |
| Deferred income taxes | 890,455 | 188,936 | (16,903) | — | 1,062,488 |
| Noncurrent liabilities from risk management activities | 1 | — | 5,300 | — | 5,301 |
| Regulatory cost of removal obligation | 414,001 | — | — | — | 414,001 |
| Deferred credits and other liabilities | 455,321 | 5,659 | 918 | — | 461,898 |
| | $7,253,268 | $1,045,369 | $528,337 | $(1,458,247) | $7,368,727 |

| | September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,248,198 | $ 838,302 | $ 61,418 | $ — | $5,147,918 |
| Investment in subsidiaries | 670,993 | — | (2,096) | (668,897) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 24,646 | — | 106,773 | — | 131,419 |
| Assets from risk management activities | 843 | — | 17,501 | — | 18,344 |
| Other current assets | 655,716 | 15,413 | 386,215 | (196,154) | 861,190 |
| Intercompany receivables | 569,898 | — | — | (569,898) | — |
| Total current assets | 1,251,103 | 15,413 | 510,489 | (766,052) | 1,010,953 |
| Intangible assets | — | — | 207 | — | 207 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | 998 | — | — | — | 998 |
| Deferred charges and other assets | 353,960 | 18,028 | 10,807 | — | 382,795 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,255,421 | $ 265,102 | $405,891 | $ (670,993) | $2,255,421 |
| Long-term debt | 2,205,986 | — | 131 | — | 2,206,117 |
| Total capitalization | 4,461,407 | 265,102 | 406,022 | (670,993) | 4,461,538 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 2,303 | — | 131 | — | 2,434 |
| Short-term debt | 387,691 | — | — | (181,295) | 206,396 |
| Liabilities from risk management activities | 11,916 | — | 3,537 | — | 15,453 |
| Other current liabilities | 474,783 | 10,369 | 170,926 | (12,763) | 643,315 |
| Intercompany payables | — | 543,084 | 26,814 | (569,898) | — |
| Total current liabilities | 876,693 | 553,453 | 201,408 | (763,956) | 867,598 |
| Deferred income taxes | 789,649 | 173,351 | (2,907) | — | 960,093 |
| Noncurrent liabilities from risk management activities | 67,862 | — | 10,227 | — | 78,089 |
| Regulatory cost of removal obligation | 428,947 | — | — | — | 428,947 |
| Deferred credits and other liabilities | 473,602 | 12,218 | 786 | — | 486,606 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of March 31, 2012, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2012 and 2011, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2012 and 2011. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2011, 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 22, 2011, 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, 2011, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
May 3, 2012

**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, 2011.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

## OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas currently located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

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

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the six months ended March 31, 2012.

## RESULTS OF OPERATIONS

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 62 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

We reported net income of $109.1 million, or $1.20 per diluted share for the three months ended March 31, 2012, compared with net income of $132.2 million or $1.45 per diluted share in the prior year. Excluding the impact of unrealized margins, diluted earnings per share decreased $0.19 compared with the prior-year quarter. Results for the prior-year period were influenced by the net positive impact of several one-time items totaling $11.1 million, or $0.12 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to a cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a previously planned debt offering.
- $19.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

After excluding the impact of unrealized margins and the one-time items, net income and diluted earnings per share for the three months ended March 31, 2012 decreased $6.4 million, or $0.07 per diluted share when compared to the prior-year period, primarily due to lower earnings in our nonregulated segment due to historically warm winter weather and unfavorable natural gas market conditions. Included in the current quarter amount is net income from discontinued operations of $3.2 million, or $0.04 per diluted share associated with the pending sale of our Missouri, Illinois and Iowa service areas, a decrease of $0.8 million or $0.00 per diluted share compared with the prior-year quarter.

During the six months ended March 31, 2012, we earned $177.6 million or $1.94 per diluted share, which represents a 14 percent decrease in net income and diluted net income per share compared with the prior-year period. Results for the prior-year period were influenced by the net positive impact of several one-time items totaling $11.1 million, or $0.12 per diluted share. Excluding the impact of these one-time items and unrealized margins in our nonregulated operations, we earned $172.3 million, or $1.88 per diluted share for the six months ended March 31, 2012, compared to $196.8 million, or $2.16 in the prior-year period. Included in the current period amount is net income from discontinued operations of $5.9 million, or $0.06 per diluted share associated with the pending sale of our Missouri, Illinois and Iowa service areas, a decrease of $1.0 million or $0.02 per diluted share compared with the prior-year period.

Our quarter-to-date and year-to-date results were unfavorably impacted by substantially warmer winter weather and an abundance of natural gas supply. The impact of these conditions was most significantly realized in our nonregulated operations, which experienced a $23.0 million six-month period-over-period decrease in net income, excluding the impact of one-time items and unrealized margins. These market conditions also contributed to a 10 percent decrease in throughput in our natural gas distribution segment and lower through-system transportation rates earned on our regulated intrastate pipeline for the six months ended March 31, 2012 compared to the six months ended March 31, 2011. However, the impact on our regulated operations was not as significant due to favorable rate designs, which substantially mitigated the effects of relatively warm weather in most of our natural gas distribution service areas and the favorable impact of rate case increases experienced in both our natural gas distribution and regulated transmission and storage segments.

During the fiscal second quarter, we undertook several steps to grow earnings in our regulated operations. In our natural gas distribution segment, we initiated seven rate proceedings requesting a total of $68.7 million in additional annual operating income and, in April 2012, we completed an annual rate filing for Atmos Pipeline-Texas (APT) that should increase annual operating income by $14.7 million. Further, we announced two significant pipeline expansion projects whereby APT will spend $150 million over the next two fiscal years to increase its ability to secure new long-term gas supply on a firm and reliable basis and to enhance the reliability of APT's service to our Mid-Tex Division in certain critical locations.

During the second fiscal quarter, we completed the annual evaluation of the funded status of our qualified defined benefit plans as of January 1, 2012 as required by the Pension Protection Act of 2006 (PPA). As a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our pension liabilities, we were required to contribute $23.0 million into the plans. For the six months ended March 31, 2012, we contributed $34.2 million into these plans and expect to contribute an additional $12.4 million for the remainder of the fiscal year. Additionally, we contributed $9.1 million into our postretirement medical plans during the six months ended March 31, 2012 and expect to contribute between $10 million and $15 million for the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

**Consolidated Results**

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2012 and 2011:

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands, except per share data) | | | |
| Operating revenues | $1,243,450 | $1,581,497 | $2,344,623 | $2,714,759 |
| Gross profit | 434,261 | 453,668 | 797,143 | 818,392 |
| Operating expenses | 225,899 | 242,469 | 444,374 | 451,904 |
| Operating income | 208,362 | 211,199 | 352,769 | 366,488 |
| Miscellaneous income (expense) | 616 | 26,202 | (1,259) | 25,476 |
| Interest charges | 36,660 | 37,875 | 72,102 | 76,770 |
| Income from continuing operations before income taxes | 172,318 | 199,526 | 279,408 | 315,194 |
| Income tax expense | 66,408 | 71,366 | 107,710 | 115,934 |
| Income from continuing operations | 105,910 | 128,160 | 171,698 | 199,260 |
| Income from discontinued operations, net of tax | 3,201 | 4,049 | 5,920 | 6,946 |
| Net income | $ 109,111 | $ 132,209 | $ 177,618 | $ 206,206 |
| Diluted net income per share from continuing operations | $ 1.16 | $ 1.41 | $ 1.88 | $ 2.18 |
| Diluted net income per share from discontinued operations | 0.04 | 0.04 | 0.06 | 0.08 |
| Diluted net income per share | $ 1.20 | $ 1.45 | $ 1.94 | $ 2.26 |

Our consolidated net income during the three and six month periods ended March 31, 2012 and 2011 was earned in each of our business segments as follows:

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Natural gas distribution segment from continuing operations | $ 98,301 | $114,561 | $(16,260) |
| Regulated transmission and storage segment | 14,620 | 17,739 | (3,119) |
| Nonregulated segment | (7,011) | (4,140) | (2,871) |
| Net income from continuing operations | 105,910 | 128,160 | (22,250) |
| Net income from discontinued operations | 3,201 | 4,049 | (848) |
| Net income | $109,111 | $132,209 | $(23,098) |

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Natural gas distribution segment from continuing operations | $146,206 | $168,982 | $(22,776) |
| Regulated transmission and storage segment | 28,034 | 27,841 | 193 |
| Nonregulated segment | (2,542) | 2,437 | (4,979) |
| Net income from continuing operations | 171,698 | 199,260 | (27,562) |
| Net income from discontinued operations | 5,920 | 6,946 | (1,026) |
| Net income | $177,618 | $206,206 | $(28,588) |

Regulated operations contributed 106 percent and 101 percent to our consolidated net income for the three and six month periods ended March 31, 2012. The following tables segregate our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $112,921 | $132,300 | $(19,379) |
| Nonregulated operations | (7,011) | (4,140) | (2,871) |
| Net income from continuing operations | 105,910 | 128,160 | (22,250) |
| Net income from discontinued operations | 3,201 | 4,049 | (848) |
| Net income | $109,111 | $132,209 | $(23,098) |
| Diluted EPS from continuing regulated operations | $ 1.23 | $ 1.45 | $ (0.22) |
| Diluted EPS from nonregulated operations | (0.07) | (0.04) | (0.03) |
| Diluted EPS from continuing operations | 1.16 | 1.41 | (0.25) |
| Diluted EPS from discontinued operations | 0.04 | 0.04 | — |
| Consolidated diluted EPS | $ 1.20 | $ 1.45 | $ (0.25) |

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $174,240 | $196,823 | $(22,583) |
| Nonregulated operations | (2,542) | 2,437 | (4,979) |
| Net income from continuing operations | 171,698 | 199,260 | (27,562) |
| Net income from discontinued operations | 5,920 | 6,946 | (1,026) |
| Net income | $177,618 | $206,206 | $(28,588) |
| Diluted EPS from continuing regulated operations | $ 1.91 | $ 2.15 | $ (0.24) |
| Diluted EPS from nonregulated operations | (0.03) | 0.03 | (0.06) |
| Diluted EPS from continuing operations | 1.88 | 2.18 | (0.30) |
| Diluted EPS from discontinued operations | 0.06 | 0.08 | (0.02) |
| Consolidated diluted EPS | $ 1.94 | $ 2.26 | $ (0.32) |

***Natural Gas Distribution Segment***

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

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for over 90 percent of our residential and commercial meters in the following states for the following time periods:

| | |
|---|---|
| Georgia, Kansas, West Texas | October — May |
| Kentucky, Mississippi, Tennessee, Mid-Tex | November — April |
| Louisiana | December — March |
| Virginia | January — December |

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources. Conversely, lower gas costs reduce our collection risk and reduce the need to utilize short-term borrowings to fund our working capital needs.

As discussed above, in May 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

***Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011***

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2012 and 2011 are presented below.

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $380,802 | $379,004 | $ 1,798 |
| Operating expenses | 191,511 | 190,909 | 602 |
| **Operating income** | 189,291 | 188,095 | 1,196 |
| Miscellaneous income | 733 | 20,156 | (19,423) |
| Interest charges | 28,833 | 29,605 | (772) |
| **Income from continuing operations before income taxes** | 161,191 | 178,646 | (17,455) |
| Income tax expense | 62,890 | 64,085 | (1,195) |
| **Income from continuing operations** | 98,301 | 114,561 | (16,260) |
| Income from discontinued operations, net of tax | 3,201 | 4,049 | (848) |
| **Net income** | $101,502 | $118,610 | $(17,108) |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 103,169 | 132,517 | (29,348) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 36,877 | 37,378 | (501) |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 140,046 | 169,895 | (29,849) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 4,848 | 6,406 | (1,558) |
| Total consolidated natural gas distribution throughput — MMcf | 144,894 | 176,301 | (31,407) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.43 | $ 0.47 | $ (0.04) |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 4.94 | $ 5.28 | $ (0.34) |

The $1.8 million increase in natural gas distribution gross profit was primarily due to a $6.4 million net increase in rate adjustments, primarily in our Mid-Tex, Mississippi and Louisiana service areas, combined with a $1.0 million increase in customers, primarily in our Mid-Tex service area.

These increases were partially offset by a $5.9 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.

Results for the second fiscal quarter were also unfavorably impacted by significantly warmer winter weather, which resulted in an 18 percent decrease in total consolidated throughput compared to the prior year. However, the impact to gross profit was mitigated by favorable rate designs that substantially lessened the impact of warm weather in most of our natural gas distribution service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $0.6 million primarily due to the following:

- $3.2 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.

• $1.1 million net increase in legal and other administrative costs.

• $1.2 million increase in software maintenance costs.

These increases were partially offset by the following:

• $2.0 million decrease in revenue-related taxes. When combined with the $5.9 million decrease in associated revenue taxes included in gross margin, we experienced a net $3.9 million quarter-over-quarter decrease in operating income.

• $1.4 million decrease due to the establishment of a regulatory asset in Texas for pension and post-retirement costs.

• $1.0 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.

Net income for this segment for the prior-year quarter was favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended March 31, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | | (In thousands) | |
| Mid-Tex | $ 88,301 | $ 82,476 | $ 5,825 |
| Kentucky/Mid-States | 24,655 | 28,837 | (4,182) |
| Louisiana | 22,470 | 23,235 | (765) |
| West Texas | 17,989 | 19,280 | (1,291) |
| Mississippi | 17,537 | 18,004 | (467) |
| Colorado-Kansas | 13,982 | 15,250 | (1,268) |
| Other | 4,357 | 1,013 | 3,344 |
| Total | $189,291 | $188,095 | $ 1,196 |

***Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011***

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2012 and 2011 are presented below.

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $671,887 | $669,940 | $ 1,947 |
| Operating expenses | 374,235 | 362,480 | 11,755 |
| **Operating income** | 297,652 | 307,460 | (9,808) |
| Miscellaneous income (expense) | (1,023) | 19,458 | (20,481) |
| Interest charges | 56,688 | 59,302 | (2,614) |
| **Income from continuing operations before income taxes** | 239,941 | 267,616 | (27,675) |
| Income tax expense | 93,735 | 98,634 | (4,899) |
| **Income from continuing operations** | 146,206 | 168,982 | (22,776) |
| Income from discontinued operations, net of tax | 5,920 | 6,946 | (1,026) |
| **Net income** | $152,126 | $175,928 | $(23,802) |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 188,059 | 216,654 | (28,595) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 69,709 | 69,596 | 113 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 257,768 | 286,250 | (28,482) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 8,874 | 10,595 | (1,721) |
| Total consolidated natural gas distribution throughput — MMcf | 266,642 | 296,845 | (30,203) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.44 | $ 0.48 | $ (0.04) |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 4.87 | $ 5.14 | $ (0.27) |

The $1.9 million increase in natural gas distribution gross profit was primarily due to an $11.0 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Mississippi, Kentucky and West Texas service areas.

These increases were partially offset by the following:

- $2.9 million decrease due to a 10 percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in the current quarter compared to the same period last year in most of our service areas.
- $5.6 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $11.8 million primarily due to the following:

- $6.1 million increase in depreciation and amortization and a $5.5 million increase in ad valorem taxes associated with an increase in our net plant as a result of our capital investments in the prior year.

- $7.6 million net increase in legal and other administrative costs.
- $1.8 million increase in software maintenance costs.

These increases were partially offset by the following:

- $4.0 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.
- $1.8 million decrease in revenue-related taxes. When combined with the $5.6 million decrease in associated revenue taxes included in gross margin, we experienced a net $3.8 million year-over-year decrease in operating income.
- $1.4 million decrease associated with the aforementioned regulatory asset.

Net income from the prior-year period also reflects the aforementioned Treasury lock gain and income tax benefit.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the six months ended March 31, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands) | | |
| Mid-Tex | $136,750 | $139,915 | $(3,165) |
| Kentucky/Mid-States | 40,973 | 45,690 | (4,717) |
| Louisiana | 37,671 | 38,196 | (525) |
| West Texas | 28,664 | 28,800 | (136) |
| Mississippi | 27,669 | 28,219 | (550) |
| Colorado-Kansas | 22,161 | 22,952 | (791) |
| Other | 3,764 | 3,688 | 76 |
| Total | $297,652 | $307,460 | $(9,808) |

*Recent Ratemaking Developments*

Significant ratemaking developments that occurred during the six months ended March 31, 2012 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $8.0 million resulting from ratemaking activity became effective in the six months ended March 31, 2012 as summarized below:

| Rate Action | Annual Increase to Operating Income |
|---|---|
| | (In thousands) |
| Rate case filings | $ 545 |
| Infrastructure programs | 3,744 |
| Annual rate filing mechanisms | 3,505 |
| Other rate activity | 167 |
| | $7,961 |

Additionally, the following ratemaking efforts were in progress during the second quarter of fiscal 2012 but had not been completed as of March 31, 2012.

| Division | Rate Action | Jurisdiction | Operating Income Requested |
|---|---|---|---|
| | | | (In thousands) |
| Mid-Tex | Rate Case | RRC | $45,980 |
| West Texas | Rate Case | RRC | 11,137 |
| Colorado-Kansas | Rate Case | Kansas | 6,134 |
| Mid-Tex | Dallas Annual Rate Review | RRC | 2,545 |
| Louisiana | Rate Stabilization Clause | LGS | 1,823 |
| Kentucky/Mid-States | PRP | Georgia | 1,079 |
| Louisiana | Rate Stabilization Clause | TransLa | — |
| | | | $68,698 |

*Rate Case Filings*

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate case that was completed during the six months ended March 31, 2012.

| Division | State | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|
| | | (In thousands) | |
| *2012 Rate Case Filings:* | | | |
| West Texas — Environs | Texas | $545 | 11/08/2011 |
| Total 2012 Rate Case Filings | | $545 | |

*Infrastructure Programs*

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates occurring during the six months ended March 31, 2012.

| Division | Period End | Incremental Net Utility Plant Investment | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | (In thousands) | (In thousands) | |
| *2012 Infrastructure Programs:* | | | | |
| Kentucky/Mid-States — Georgia | 09/2010 | $ 7,160 | $1,215 | 10/01/2011 |
| Kentucky/Mid-States — Kentucky | 09/2012 | 17,347 | 2,529 | 10/01/2011 |
| Total 2012 Infrastructure Programs | | $24,507 | $3,744 | |

*Annual Rate Filing Mechanisms*

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and the Georgia service area in our Kentucky/Mid-States Division. The Company is requesting new annual rate filing mechanisms as part of our ongoing rate cases in our Mid-Tex and West Texas divisions to replace the annual mechanisms that expired for significant portions of these service areas in 2011. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the six months ended March 31, 2012.

| Division | Jurisdiction | Test Year Ended | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2012 Filings:* | | | | |
| Kentucky/Mid-States | Georgia | 09/30/2011 | $ (818) | 02/01/2012 |
| Mississippi | Mississippi | 06/30/2011 | 4,323 | 01/11/2012 |
| Total 2012 Filings | | | $3,505 | |

*Other Ratemaking Activity*

The following table summarizes other ratemaking activity during the six months ended March 31, 2012:

| Division | Jurisdiction | Rate Activity | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2012 Other Rate Activity:* | | | | |
| Colorado-Kansas | Kansas | Ad Valorem[1] | $167 | 01/14/2012 |
| Total 2012 Other Rate Activity | | | $167 | |

[1] The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas area's base rates.

***Regulated Transmission and Storage Segment***

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

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

***Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011***

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2012 and 2011 are presented below.

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 39,114 | $ 33,096 | $ 6,018 |
| Third-party transportation | 14,309 | 16,811 | (2,502) |
| Storage and park and lend services | 1,867 | 2,219 | (352) |
| Other | 2,747 | 2,850 | (103) |
| **Gross profit** | 58,037 | 54,976 | 3,061 |
| Operating expenses | 27,554 | 25,142 | 2,412 |
| **Operating income** | 30,483 | 29,834 | 649 |
| Miscellaneous income (expense) | (56) | 5,861 | (5,917) |
| Interest charges | 7,614 | 8,085 | (471) |
| **Income before income taxes** | 22,813 | 27,610 | (4,797) |
| Income tax expense | 8,193 | 9,871 | (1,678) |
| **Net income** | $ 14,620 | $ 17,739 | $ (3,119) |
| Gross pipeline transportation volumes — MMcf | 176,361 | 174,471 | 1,890 |
| Consolidated pipeline transportation volumes — MMcf | 109,626 | 93,493 | 16,133 |

The $3.1 million increase in regulated transmission and storage gross profit compared to the prior-year quarter was primarily a result of rate design changes approved in the rate case in the prior year. The current rate design allows us to recover fixed costs associated with transportation and storage services through monthly customer charges rather than through a volumetric charge, which should allow us to earn margin more ratably during the fiscal year. Therefore, despite an 18 percent decrease in throughput to our Mid-Tex Division, we experienced an 18 percent increase in gross profit from Mid-Tex transportation.

For the quarter, the enhanced rate design resulted in an $8.4 million increase in gross profit compared to the prior-year quarter. This increase was partially offset by the following:

- $3.0 million decrease associated with lower throughput to our Mid-Tex Division.
- $1.5 million decrease in third-party transportation. Throughput associated with third-party transportation increased 17 percent due to the execution of new delivery contracts with local producers in the Barnett Shale region. However, these increases were more than offset by lower transportation rates.

Operating expenses increased $2.4 million primarily due to the following:

- $0.5 million increase due to higher pipeline maintenance costs.
- $2.0 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

Net income for this segment for the prior-year quarter was favorably impacted by a $6.0 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks.

On April 10, 2012, the RRC approved the Atmos Pipeline — Texas GRIP filing that was filed in February 2012. The Commission approved an annual operating income increase of $14.7 million that went into effect with bills rendered on and after April 10, 2012.

*Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011*

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2012 and 2011 are presented below.

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 76,457 | $ 60,631 | $15,826 |
| Third-party transportation | 29,248 | 33,323 | (4,075) |
| Storage and park and lend services | 3,673 | 4,389 | (716) |
| Other | 5,418 | 5,640 | (222) |
| **Gross profit** | 114,796 | 103,983 | 10,813 |
| Operating expenses | 55,954 | 50,068 | 5,886 |
| **Operating income** | 58,842 | 53,915 | 4,927 |
| Miscellaneous income (expense) | (336) | 5,579 | (5,915) |
| Interest charges | 14,823 | 16,149 | (1,326) |
| **Income before income taxes** | 43,683 | 43,345 | 338 |
| Income tax expense | 15,649 | 15,504 | 145 |
| **Net income** | $ 28,034 | $ 27,841 | $ 193 |
| Gross pipeline transportation volumes — MMcf | 337,190 | 327,649 | 9,541 |
| Consolidated pipeline transportation volumes — MMcf | 214,663 | 193,334 | 21,329 |

The $10.8 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the previously discussed rate design changes approved in the rate case in the prior year. Therefore, despite a nine percent decrease in throughput to our Mid-Tex Division, we experienced a 26 percent increase in gross profit from Mid-Tex transportation.

For the year-to-date period, the enhanced rate design resulted in a $16.9 million increase in gross profit compared to the prior-year period. This increase was partially offset by the following:

- $2.5 million decrease associated with lower throughput to our Mid-Tex Division.
- $2.5 million decrease in third-party transportation. Throughput associated with third-party transportation increased 11 percent due to the execution of new delivery contracts with local producers in the Barnett Shale region. However, these increases were more than offset by lower transportation rates.

Operating expenses increased $5.9 million primarily due to the following:

- $1.8 million increase due to higher pipeline maintenance costs.
- $3.8 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

Net income from the prior-year period also reflects the aforementioned Treasury lock gain.

*Nonregulated Segment*

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. This business is significantly influenced by competitive factors in the industry, general economic conditions and other factors that could affect the demand for natural gas. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas used to serve those customers. Further, delivered gas margins can be affected by the price of natural gas in the different locations where we buy and sell gas.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions. These margins are influenced by natural gas market conditions including, but not limited to, the price of natural gas, demand for natural gas, the level of domestic natural gas inventory levels and the level of volatility between current (spot) and future natural gas prices. These margins are also impacted by our ability to minimize the demand fees paid to contract for storage capacity.

Higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices may also cause customers to conserve or use alternative energy sources. Lower natural gas prices generally reduce these risks.

The level of volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads and basis differentials from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Conversely, a lack of price volatility reduces opportunities to create value from arbitrage spreads and basis differentials.

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

***Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011***

Financial and operational highlights for our nonregulated segment for the three months ended March 31, 2012 and 2011 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

| | Three Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 14,271 | $ 19,170 | $ (4,899) |
| Storage and transportation services | 3,451 | 3,522 | (71) |
| Other | 996 | 1,460 | (464) |
| | 18,718 | 24,152 | (5,434) |
| Asset optimization[1] | (10,045) | (686) | (9,359) |
| **Total realized margins** | 8,673 | 23,466 | (14,793) |
| **Unrealized margins** | (12,902) | (3,408) | (9,494) |
| **Gross profit** | (4,229) | 20,058 | (24,287) |
| Operating expenses, excluding asset impairment | 7,185 | 7,506 | (321) |
| Asset impairment | — | 19,282 | (19,282) |
| **Operating loss** | (11,414) | (6,730) | (4,684) |
| Miscellaneous income | 567 | 306 | 261 |
| Interest charges | 839 | 306 | 533 |
| **Loss before income taxes** | (11,686) | (6,730) | (4,956) |
| Income tax benefit | (4,675) | (2,590) | (2,085) |
| **Net loss** | $ (7,011) | $ (4,140) | $ (2,871) |
| Gross nonregulated delivered gas sales volumes — MMcf | 111,656 | 127,377 | (15,721) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 99,844 | 107,566 | (7,722) |
| Net physical position (Bcf) | 38.0 | 17.7 | 20.3 |

[1] Net of storage fees of $4.8 million and $3.6 million.

Results for our nonregulated operations during the second fiscal quarter continue to be adversely influenced by unfavorable natural gas market conditions. Historically high natural gas storage levels caused by strong domestic natural gas production coupled with lower demand driven by an unseasonably warm 2011-2012 winter heating season caused natural gas prices to remain relatively low during our fiscal second quarter. As a result, we continue to experience compressed spot to forward spread values and basis differentials. Additionally, we experienced a quarter-over-quarter decrease in sales volumes due to the relatively warm weather.

We anticipate natural gas storage levels will remain high for an extended period of time. Therefore, we anticipate that basis differentials will remain compressed, which will limit arbitrage and sales opportunities from buying gas in one location and delivering gas into another location. Additionally, we expect gas prices will remain relatively low with lower spot to forward spread volatility relative to recent years. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be lower than in previous years for the foreseeable future.

Realized margins for gas delivery, storage and transportation services and other services were $18.7 million during the three months ended March 31, 2012 compared with $24.2 million for the prior-year quarter. The decrease reflects the following:

- A seven percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.13/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply. The decrease in basis differentials was partially offset by increased fees earned from certain transportation arrangements and the receipt of a one-time refund of transportation demand fees from one of our transporters.

Asset optimization margins decreased $9.4 million from the prior-year quarter. In the current year quarter, AEH continued to take advantage of falling natural gas prices by purchasing and injecting a net 8.9 Bcf into storage and capturing incremental physical to forward spread values that should be realized primarily in the third and fourth quarter of fiscal 2012. As a result of this decision and falling prices, we realized significantly higher losses on the settlement of financial instruments used to hedge our natural gas purchases. Additionally, AEH experienced increased storage fees associated with increased park and loan activity.

The $9.5 million decrease in unrealized margins primarily reflects the impact of falling prices on our physical inventory as this hedged inventory is marked to market.

Operating expenses, excluding asset impairment, decreased $0.3 million primarily due to lower employee-related expenses. In the prior-year quarter, an asset impairment charge of $19.3 million was recorded related to our investment in Fort Necessity, which resulted in a write-off of substantially all of our investment in the project.

*Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011*

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2012 and 2011 are presented below.

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 25,384 | $ 35,211 | $ (9,827) |
| Storage and transportation services | 6,640 | 6,871 | (231) |
| Other | 2,013 | 2,779 | (766) |
| | 34,037 | 44,861 | (10,824) |
| Asset optimization[1] | (31,639) | 3,279 | (34,918) |
| **Total realized margins** | 2,398 | 48,140 | (45,742) |
| **Unrealized margins** | 8,778 | (2,904) | 11,682 |
| **Gross profit** | 11,176 | 45,236 | (34,060) |
| Operating expenses, excluding asset impairment | 14,904 | 20,841 | (5,937) |
| Asset impairment | — | 19,282 | (19,282) |
| **Operating income (loss)** | (3,728) | 5,113 | (8,841) |
| Miscellaneous income | 603 | 596 | 7 |
| Interest charges | 1,091 | 1,476 | (385) |
| **Income (loss) before income taxes** | (4,216) | 4,233 | (8,449) |
| Income tax expense (benefit) | (1,674) | 1,796 | (3,470) |
| **Net income (loss)** | $ (2,542) | $ 2,437 | $ (4,979) |
| Gross nonregulated delivered gas sales volumes — MMcf | 218,118 | 235,089 | (16,971) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 190,714 | 202,104 | (11,390) |
| Net physical position (Bcf) | 38.0 | 17.7 | 20.3 |

[1] Net of storage fees of $9.5 million and $6.9 million.

Realized margins for gas delivery, storage and transportation services and other services were $34.0 million during the six months ended March 31, 2012 compared with $44.9 million for the prior-year period. The decrease reflects the following:

- A six percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.12/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply. The decrease in basis differentials was partially offset by increased fees earned from certain transportation arrangements and the receipt of a one-time refund of transportation demand fees from one of our transporters.

Asset optimization margins decreased $34.9 million from the prior-year period. The period-over-period decrease primarily reflects AEH's decision to take advantage of falling natural prices by purchasing and injecting a net 24.6 Bcf into storage and capturing incremental physical to forward spread values that should be realized primarily in the third and fourth quarter of fiscal 2012. As a result of this decision and falling prices, we realized significantly higher losses on the settlement of financial instruments used to hedge our natural gas purchases. Additionally, AEH experienced increased storage fees associated with increased park and loan activity. Finally, AEH incurred a $1.7 million charge in the first fiscal quarter to write-down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Unrealized margins increased $11.7 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses, excluding asset impairment decreased $5.9 million primarily due to lower employee-related expenses. Asset impairment includes the aforementioned pre-tax impairment charge recorded in the prior-year period related to the write-off of substantially all of the Fort Necessity project.

### Liquidity and Capital Resources

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2012.

### Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the six months ended March 31, 2012 and 2011 are presented below.

| | Six Months Ended March 31 | | |
|---|---|---|---|
| | 2012 | 2011 | Change |
| | | (In thousands) | |
| Total cash provided by (used in) | | | |
| Operating activities | $ 360,723 | $ 438,471 | $ (77,748) |
| Investing activities | (315,001) | (248,198) | (66,803) |
| Financing activities | (130,101) | (168,979) | 38,878 |
| Change in cash and cash equivalents | (84,379) | 21,294 | (105,673) |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 | (533) |
| Cash and cash equivalents at end of period | $ 47,040 | $ 153,246 | $(106,206) |

*Cash flows from operating activities*

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

For the six months ended March 31, 2012, we generated operating cash flow of $360.7 million from operating activities compared with $438.5 million for the six months ended March 31, 2011. The $77.7 million decrease in operating cash flows primarily reflects the effect of purchasing natural gas and injecting it into storage in our nonregulated operations in order to capture incremental value anticipated to be realized in the third and fourth quarter of fiscal 2012, combined with $43.3 million in contributions made to our pension and postretirement plans during the first six months of fiscal 2012 and the timing of customer collections and vendor payments.

*Cash flows from investing activities*

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

Capital expenditures for fiscal 2012 are currently expected to range from $690 million to $710 million. For the six months ended March 31, 2012, capital expenditures were $311.1 million compared with $246.7 million for the six months ended March 31, 2011. The $64.4 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and other infrastructure replacement projects in our Mid-Tex, West Texas and Kentucky service areas, the development of new customer billing and information systems for our natural gas distribution segment and increased capital spending to increase the capacity on our Atmos Pipeline — Texas system.

*Cash flows from financing activities*

For the six months ended March 31, 2012, our financing activities used $130.1 million of cash compared with $169.0 million of cash used in the prior-year period, primarily due to lower cash outflows associated with repayment of our short-term and long-term debt instruments, as follows:

- $80.0 million for short-term debt repayments. In the current-year period, $48.9 million of short-term debt was repaid, compared with $128.9 million in the prior-year period.
- $7.7 million for scheduled long-term debt repayments. In the current-year period, $2.4 million of long-term debt was repaid, compared with $10.1 million in the prior-year period.

The lower repayment activity was partially offset by:

- $27.8 million less cash received related to the unwinding of two Treasury locks in the prior year.
- $12.5 million additional cash used to repurchase common stock as part of our share buyback program.
- $7.4 million less cash received from proceeds related to the issuance of common stock.

The following table summarizes our share issuances for the six months ended March 31, 2012 and 2011.

| | Six Months Ended March 31 | |
|---|---|---|
| | 2012 | 2011 |
| Shares issued: | | |
| 1998 Long-Term Incentive Plan | 219,712 | 663,555 |
| Outside Directors Stock-for-Fee Plan | 1,204 | 1,232 |
| Total shares issued | 220,916 | 664,787 |

The year-over-year decrease in the number of shares issued primarily reflects the significant number of stock options exercised in the prior year. During the current-year period, we cancelled and retired 99,555 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares through our 2011 share repurchase program described in Note 7.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our 1998 Long-Term Incentive Plan (LTIP). In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

### Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of March 31, 2012, the amount available to us under our credit facilities, net of outstanding letters of credit, was $687.2 million.

### Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At March 31, 2012, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

### Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of March 31, 2012, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Unsecured senior long-term debt | BBB+ | Baa1 | A- |
| Commercial paper | A-2 | P-2 | F-2 |

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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

### Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2012. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

### Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2012, September 30, 2011 and March 31, 2011:

| | March 31, 2012 | | September 30, 2011 | | March 31, 2011 | |
|---|---|---|---|---|---|---|
| | (In thousands, except percentages) | | | | | |
| Short-term debt | $ 173,996 | 3.7% | $ 206,396 | 4.4% | $ — | — |
| Long-term debt | 2,206,344 | 46.5% | 2,208,551 | 47.3% | 2,159,757 | 47.6% |
| Shareholders' equity | 2,360,712 | 49.8% | 2,255,421 | 48.3% | 2,373,979 | 52.4% |
| Total | $4,741,052 | 100.0% | $4,670,368 | 100.0% | $4,533,736 | 100.0% |

Total debt as a percentage of total capitalization, including short-term debt, was 50.2 percent at March 31, 2012, 51.7 percent at September 30, 2011 and 47.6 percent at March 31, 2011. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

### Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2012.

### Risk Management Activities

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and six months ended March 31, 2012 and 2011:

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $(85,829) | $ 26,806 | $(79,277) | $ (49,600) |
| Contracts realized/settled | (13,807) | (18,064) | (31,537) | (51,045) |
| Fair value of new contracts | 176 | 540 | (377) | 1,071 |
| Other changes in value | 51,928 | 21,251 | 63,659 | 130,107 |
| Fair value of contracts at end of period | $(47,532) | $ 30,533 | $(47,532) | $ 30,533 |

The fair value of our natural gas distribution segment's financial instruments at March 31, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(47,531) | $ (1) | $— | $— | $(47,532) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(47,531) | $ (1) | $— | $— | $(47,532) |

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2012 and 2011:

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $(15,263) | $(10,681) | $(25,050) | $(12,374) |
| Contracts realized/settled | 13,779 | (1,009) | 31,228 | (75) |
| Fair value of new contracts | — | — | — | — |
| Other changes in value | (1,090) | (1,252) | (8,752) | (493) |
| Fair value of contracts at end of period | (2,574) | (12,942) | (2,574) | (12,942) |
| Netting of cash collateral | 5,696 | 17,053 | 5,696 | 17,053 |
| Cash collateral and fair value of contracts at period end | $ 3,122 | $ 4,111 | $ 3,122 | $ 4,111 |

The fair value of our nonregulated segment's financial instruments at March 31, 2012 is presented below by time period and fair value source:

| | Fair Value of Contracts at March 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(8,115) | $5,563 | $(22) | $— | $(2,574) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(8,115) | $5,563 | $(22) | $— | $(2,574) |

**Pension and Postretirement Benefits Obligations**

For the six months ended March 31, 2012 and 2011, our total net periodic pension and other benefits costs were $34.6 million and $28.8 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2012 pension and postretirement medical costs for the six months ended March 31, 2012 were higher than the prior-year period.

The amounts we fund our defined benefit plans with are determined in accordance with the PPA and are influenced by the discount rate and funded position of the plans when the funding requirements are determined on January 1 of each year. We completed our valuation for fiscal 2012 during the second fiscal quarter and as a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our qualified pension liabilities, we were required to contribute $23.0 million to the plans. During the six months ended March 31, 2012, we contributed $34.2 million to our defined benefit plans and we anticipate contributing an additional $12.4 million during the remainder of the fiscal year. Additionally, we contributed $9.1 million to our postretirement medical plans during the six months ended March 31, 2012 and anticipate contributing between $10 million and $15 million to these plans during the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

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

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and six month periods ended March 31, 2012 and 2011.

*Natural Gas Distribution Sales and Statistical Data — Continuing Operations*

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| **METERS IN SERVICE, end of period** | | | | |
| Residential | 2,862,546 | 2,856,181 | 2,862,546 | 2,856,181 |
| Commercial | 261,449 | 260,010 | 261,449 | 260,010 |
| Industrial | 2,281 | 2,323 | 2,281 | 2,323 |
| Public authority and other | 10,245 | 10,194 | 10,245 | 10,194 |
| Total meters | 3,136,521 | 3,128,708 | 3,136,521 | 3,128,708 |
| **INVENTORY STORAGE BALANCE — Bcf** | 33.2 | 28.2 | 33.2 | 28.2 |
| **SALES VOLUMES — MMcf** [2] | | | | |
| Gas sales volumes | | | | |
| Residential | 63,362 | 82,920 | 113,602 | 133,076 |
| Commercial | 31,667 | 39,456 | 58,271 | 65,485 |
| Industrial | 4,697 | 6,046 | 10,109 | 11,192 |
| Public authority and other | 3,443 | 4,095 | 6,077 | 6,901 |
| Total gas sales volumes | 103,169 | 132,517 | 188,059 | 216,654 |
| Transportation volumes | 38,069 | 38,571 | 72,036 | 71,788 |
| Total throughput | 141,238 | 171,088 | 260,095 | 288,442 |
| **OPERATING REVENUES (000's)**[2] | | | | |
| Gas sales revenues | | | | |
| Residential | $ 589,108 | $ 702,858 | $1,026,617 | $1,146,497 |
| Commercial | 229,204 | 285,680 | 418,892 | 474,945 |
| Industrial | 25,148 | 34,427 | 51,855 | 63,116 |
| Public authority and other | 21,749 | 27,546 | 39,243 | 46,083 |
| Total gas sales revenues | 865,209 | 1,050,511 | 1,536,607 | 1,730,641 |
| Transportation revenues | 15,867 | 17,727 | 30,729 | 33,418 |
| Other gas revenues | 7,932 | 9,176 | 14,964 | 16,817 |
| Total operating revenues | $ 889,008 | $1,077,414 | $1,582,300 | $1,780,876 |
| Average transportation revenue per Mcf[1] | $ 0.42 | $ 0.46 | $ 0.43 | $ 0.47 |
| Average cost of gas per Mcf sold[1] | $ 4.94 | $ 5.28 | $ 4.87 | $ 5.14 |

See footnote following these tables.

*Natural Gas Distribution Sales and Statistical Data — Discontinued Operations*

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Meters in service, end of period | 83,524 | 84,323 | 83,524 | 84,323 |
| Inventory storage balance — Bcf | 2.2 | 1.9 | 2.2 | 1.9 |
| Sales volumes — MMcf | | | | |
| Total gas sales volumes | 3,094 | 4,321 | 5,523 | 6,974 |
| Transportation volumes | 1,754 | 2,085 | 3,351 | 3,621 |
| Total throughput | 4,848 | 6,406 | 8,874 | 10,595 |
| Operating revenues (000's) | $26,374 | $35,790 | $49,825 | $59,523 |

*Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data*

| | Three Months Ended March 31 | | Six Months Ended March 31 | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| **CUSTOMERS, end of period** | | | | |
| Industrial | 781 | 753 | 781 | 753 |
| Municipal | 139 | 62 | 139 | 62 |
| Other | 444 | 513 | 444 | 513 |
| Total | 1,364 | 1,328 | 1,364 | 1,328 |
| **NONREGULATED INVENTORY STORAGE BALANCE — Bcf** | 49.0 | 23.3 | 49.0 | 23.3 |
| **REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[2]** | 176,361 | 174,471 | 337,190 | 327,649 |
| **NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[2]** | 111,656 | 127,377 | 218,118 | 235,089 |
| **OPERATING REVENUES (000's)[2]** | | | | |
| Regulated transmission and storage | $ 58,037 | $ 54,976 | $114,796 | $ 103,983 |
| Nonregulated | 370,763 | 583,531 | 814,939 | 1,059,171 |
| Total operating revenues | $428,800 | $638,507 | $929,735 | $1,163,154 |

Notes to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

## RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012, there were no material changes in our quantitative and qualitative disclosures about market risk.

## Item 4. *Controls and Procedures*

### Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

# PART II. OTHER INFORMATION

## Item 1. *Legal Proceedings*

During the six months ended March 31, 2012, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

## Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. We did not repurchase any shares during the second quarter of fiscal 2012. At March 31, 2012, there were 4,612,009 shares of repurchase authority remaining under the program.

## Item 6. *Exhibits*

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

## SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: May 3, 2012

## EXHIBITS INDEX
## Item 6

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 12 | Computation of ratio of earnings to fixed charges | |
| 15 | Letter regarding unaudited interim financial information | |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications* | |
| 101.INS | XBRL Instance Document ** | |
| 101.SCH | XBRL Taxonomy Extension Schema ** | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase ** | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase ** | |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase ** | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase ** | |

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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

# Form 10-Q

(Mark One)

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

**For the quarterly period ended December 31, 2011**

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of February 3, 2012.

| Class | Shares Outstanding |
|---|---|
| No Par Value | 90,016,074 |

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AOCI | Accumulated other comprehensive income |
| APS | Atmos Pipeline and Storage, LLC |
| Bcf | Billion cubic feet |
| CFTC | Commodity Futures Trading Commission |
| FASB | Financial Accounting Standards Board |
| Fitch | Fitch Ratings, Ltd. |
| GAAP | Generally Accepted Accounting Principles |
| GRIP | Gas Reliability Infrastructure Program |
| GSRS | Gas System Reliability Surcharge |
| ISRS | Infrastructure System Replacement Surcharge |
| LPSC | Louisiana Public Service Commission |
| Mcf | Thousand cubic feet |
| MMcf | Million cubic feet |
| MPSC | Mississippi Public Service Commission |
| Moody's | Moody's Investors Services, Inc. |
| NYMEX | New York Mercantile Exchange, Inc. |
| PPA | Pension Protection Act of 2006 |
| PRP | Pipeline Replacement Program |
| RRC | Railroad Commission of Texas |
| RRM | Rate Review Mechanism |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| WNA | Weather Normalization Adjustment |

## PART I. FINANCIAL INFORMATION

**Item 1.** *Financial Statements*

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED BALANCE SHEETS

| | December 31, 2011 | September 30, 2011 |
|---|---|---|
| | (Unaudited) (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $6,896,521 | $6,816,794 |
| Less accumulated depreciation and amortization | 1,650,308 | 1,668,876 |
| Net property, plant and equipment | 5,246,213 | 5,147,918 |
| Current assets | | |
| Cash and cash equivalents | 85,160 | 131,419 |
| Accounts receivable, net | 489,797 | 273,303 |
| Gas stored underground | 325,669 | 289,760 |
| Other current assets | 360,615 | 316,471 |
| Total current assets | 1,261,241 | 1,010,953 |
| Goodwill and intangible assets | 740,196 | 740,207 |
| Deferred charges and other assets | 387,982 | 383,793 |
| | $7,635,632 | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2011 — 90,007,057 shares September 30, 2011 — 90,296,482 shares | $ 448 | $ 451 |
| Additional paid-in capital | 1,725,050 | 1,732,935 |
| Retained earnings | 607,485 | 570,495 |
| Accumulated other comprehensive loss | (65,221) | (48,460) |
| Shareholders' equity | 2,267,762 | 2,255,421 |
| Long-term debt | 2,206,193 | 2,206,117 |
| Total capitalization | 4,473,955 | 4,461,538 |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 432,332 | 291,205 |
| Other current liabilities | 357,353 | 367,563 |
| Short-term debt | 389,985 | 206,396 |
| Current maturities of long-term debt | 131 | 2,434 |
| Total current liabilities | 1,179,801 | 867,598 |
| Deferred income taxes | 981,559 | 960,093 |
| Regulatory cost of removal obligation | 437,660 | 428,947 |
| Deferred credits and other liabilities | 562,657 | 564,695 |
| | $7,635,632 | $7,282,871 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $ 693,292 | $ 703,462 |
| Regulated transmission and storage segment | 56,759 | 49,007 |
| Nonregulated segment | 444,176 | 475,640 |
| Intersegment eliminations | (93,054) | (94,847) |
| | 1,101,173 | 1,133,262 |
| Purchased gas cost | | |
| Natural gas distribution segment | 402,207 | 412,526 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 428,771 | 450,462 |
| Intersegment eliminations | (92,687) | (94,450) |
| | 738,291 | 768,538 |
| Gross profit | 362,882 | 364,724 |
| Operating expenses | | |
| Operation and maintenance | 116,062 | 114,490 |
| Depreciation and amortization | 59,215 | 54,777 |
| Taxes, other than income | 43,198 | 40,168 |
| Total operating expenses | 218,475 | 209,435 |
| Operating income | 144,407 | 155,289 |
| Miscellaneous expense | (1,875) | (726) |
| Interest charges | 35,442 | 38,895 |
| Income from continuing operations before income taxes | 107,090 | 115,668 |
| Income tax expense | 41,302 | 44,568 |
| Income from continuing operations | 65,788 | 71,100 |
| Income from discontinued operations, net of tax ($1,559 and $1,890) | 2,719 | 2,897 |
| Net income | $ 68,507 | $ 73,997 |
| Basic earnings per share | | |
| Income per share from continuing operations | $ 0.72 | $ 0.78 |
| Income per share from discontinued operations | 0.03 | 0.03 |
| Net income per share — basic | $ 0.75 | $ 0.81 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 0.72 | $ 0.78 |
| Income per share from discontinued operations | 0.03 | 0.03 |
| Net income per share — diluted | $ 0.75 | $ 0.81 |
| Cash dividends per share | $ 0.345 | $ 0.340 |
| Weighted average shares outstanding: | | |
| Basic | 90,254 | 90,082 |
| Diluted | 90,546 | 90,408 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (Unaudited) (In thousands) | |
| Cash Flows From Operating Activities | | |
| Net income | $ 68,507 | $ 73,997 |
| Adjustments to reconcile net income to net cash provided (used) by operating activities: | | |
| Depreciation and amortization: | | |
| Charged to depreciation and amortization | 60,733 | 56,161 |
| Charged to other accounts | 78 | 46 |
| Deferred income taxes | 40,042 | 43,423 |
| Other | 4,692 | 4,712 |
| Net assets / liabilities from risk management activities | (8,426) | 5,304 |
| Net change in operating assets and liabilities | (180,917) | (137,819) |
| Net cash provided (used) by operating activities | (15,291) | 45,824 |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (154,394) | (123,162) |
| Other, net | (1,080) | (370) |
| Net cash used in investing activities | (155,474) | (123,532) |
| Cash Flows From Financing Activities | | |
| Net increase in short-term debt | 173,905 | 112,628 |
| Repayment of long-term debt | (2,303) | (10,000) |
| Cash dividends paid | (31,517) | (31,002) |
| Repurchase of common stock | (12,535) | — |
| Repurchase of equity awards | (3,120) | (3,231) |
| Issuance of common stock | 76 | 7,253 |
| Net cash provided by financing activities | 124,506 | 75,648 |
| Net decrease in cash and cash equivalents | (46,259) | (2,060) |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 |
| Cash and cash equivalents at end of period | $ 85,160 | $ 129,892 |

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)
December 31, 2011

## 1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other non-regulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

We operate the Company through the following three segments:

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

## 2. Unaudited Interim Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2011 are not indicative of our results of operations for the full 2012 fiscal year, which ends September 30, 2012.

We have evaluated subsequent events from the December 31, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

***Significant accounting policies***

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard defers the effective date for amendments to the presentation of reclassifications of items out of accumulated other comprehensive income as prescribed by a previously issued standard, which were initially to be effective for interim and annual periods beginning after December 15, 2011. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the quarter ended December 31, 2011.

***Regulatory assets and liabilities***

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2011 and September 30, 2011 included the following:

| | December 31, 2011 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| **Regulatory assets:** | | |
| Pension and postretirement benefit costs | $249,882 | $254,666 |
| Merger and integration costs, net | 6,120 | 6,242 |
| Deferred gas costs | 88,799 | 33,976 |
| Regulatory cost of removal asset | 9,875 | 8,852 |
| Environmental costs | 288 | 385 |
| Rate case costs | 4,493 | 4,862 |
| Deferred franchise fees | 365 | 379 |
| Other | 3,345 | 3,534 |
| | $363,167 | $312,896 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 1,871 | $ 8,130 |
| Regulatory cost of removal obligation | 469,685 | 464,025 |
| Other | 14,558 | 14,025 |
| | $486,114 | $486,180 |

The amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of December 31, 2011, we had deferred $0.1 million associated with the requirements of this rule which are recorded as other costs in the regulatory assets table above.

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

***Comprehensive income***

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2011 and 2010:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Net income | $ 68,507 | $ 73,997 |
| Unrealized holding gains on investments, net of tax expense of $514 and $455 for the three months ended December 31, 2011 and 2010 | 901 | 776 |
| Amortization and unrealized gain (loss) on treasury lock agreements, net of tax expense (benefit) of $(638) and $18,704 for the three months ended December 31, 2011 and 2010 | (1,087) | 31,847 |
| Net unrealized gains (losses) on cash flow hedging transactions, net of tax expense (benefit) of $(10,597) and $6,617 for the three months ended December 31, 2011 and 2010 | (16,575) | 10,350 |
| Comprehensive income | $ 51,746 | $116,970 |

Accumulated other comprehensive loss, net of tax, as of December 31, 2011 and September 30, 2011 consisted of the following unrealized gains (losses):

| | December 31, 2011 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive loss: | | |
| Unrealized holding gains on investments | $ 3,459 | $ 2,558 |
| Treasury lock agreements | (35,244) | (34,157) |
| Cash flow hedges | (33,436) | (16,861) |
| | $(65,221) | $(48,460) |

## 3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the first quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

***Regulated Commodity Risk Management Activities***

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

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

***Nonregulated Commodity Risk Management Activities***

The primary business in our nonregulated operations is to aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. We utilize proprietary and customer-owned transportation and storage assets to serve these customers, and will seek to maximize the value of this storage capacity through the arbitrage of pricing differences that occur over time by selling financial instruments at advantageous prices to lock in a gross profit margin to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 59 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

### *Interest Rate Risk Management Activities*

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

As of December 31, 2011, we had three Treasury lock agreements outstanding to fix the Treasury yield component of $350 million 30-year unsecured notes, which we plan to issue to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

### *Quantitative Disclosures Related to Financial Instruments*

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

As of December 31, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

| Contract Type | Hedge Designation | Natural Gas Distribution | Nonregulated |
|---|---|---|---|
| | | Quantity (MMcf) | |
| Commodity contracts | Fair Value | — | (26,690) |
| | Cash Flow | — | 44,428 |
| | Not designated | 13,964 | 46,944 |
| | | 13,964 | 64,682 |

*Financial Instruments on the Balance Sheet*

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2011 and September 30, 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $22.1 million and $28.8 million of cash held on deposit as of December 31, 2011 and September 30, 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **December 31, 2011:** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 60,222 | $ 60,222 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 58 | 58 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | — | (57,988) | (57,988) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (69,755) | (12,012) | (81,767) |
| **Total** | | (69,755) | (9,720) | (79,475) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 292 | 148,669 | 148,961 |
| Noncurrent commodity contracts | Deferred charges and other assets | 180 | 80,916 | 81,096 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[(1)] | (16,196) | (166,878) | (183,074) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (350) | (68,250) | (68,600) |
| **Total** | | (16,074) | (5,543) | (21,617) |
| **Total Financial Instruments** | | $(85,829) | $ (15,263) | $(101,092) |

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.7 million related to risk management liabilities that were classified as assets held for sale at December 31, 2011.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **September 30, 2011:** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 22,396 | $ 22,396 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 174 | 174 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | — | (31,064) | (31,064) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (67,527) | (7,709) | (75,236) |
| **Total** | | (67,527) | (16,203) | (83,730) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 843 | 67,710 | 68,553 |
| Noncurrent commodity contracts | Deferred charges and other assets | 998 | 22,379 | 23,377 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities[1] | (13,256) | (73,865) | (87,121) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (335) | (25,071) | (25,406) |
| **Total** | | (11,750) | (8,847) | (20,597) |
| **Total Financial Instruments** | | $(79,277) | $(25,050) | $(104,327) |

[1] Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

*Impact of Financial Instruments on the Income Statement*

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $8.4 million and $13.5 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

*Fair Value Hedges*

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2011 and 2010 is presented below.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Commodity contracts | $ 24,064 | $ (1,723) |
| Fair value adjustment for natural gas inventory designated as the hedged item | (15,249) | 15,625 |
| Total impact on revenue | $ 8,815 | $13,902 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 841 | $ 921 |
| Timing ineffectiveness | 7,974 | 12,981 |
| | $ 8,815 | $13,902 |

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the three months ended December 31, 2011, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the three months ended December 31, 2010.

*Cash Flow Hedges*

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | Three Months Ended December 31, 2011 | | |
|---|---|---|---|
| | Natural Gas Distribution | Nonregulated | Consolidated |
| | | (In thousands) | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $(11,642) | $(11,642) |
| Loss arising from ineffective portion of commodity contracts | — | (430) | (430) |
| Total impact on revenue | — | (12,072) | (12,072) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (502) | — | (502) |
| Total Impact from Cash Flow Hedges | $(502) | $(12,072) | $(12,574) |

| | Three Months Ended December 31, 2010 | | |
|---|---|---|---|
| | Natural Gas Distribution | Nonregulated | Consolidated |
| | | (In thousands) | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $(14,253) | $(14,253) |
| Loss arising from ineffective portion of commodity contracts | — | (444) | (444) |
| Total impact on revenue | — | (14,697) | (14,697) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (670) | — | (670) |
| Total Impact from Cash Flow Hedges | $(670) | $(14,697) | $(15,367) |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| *Increase (decrease) in fair value:* | | |
| Treasury lock agreements | $ (1,403) | $31,425 |
| Forward commodity contracts | (23,678) | 1,657 |
| *Recognition of losses in earnings due to settlements:* | | |
| Treasury lock agreements | 316 | 422 |
| Forward commodity contracts | 7,103 | 8,693 |
| Total other comprehensive income (loss) from hedging, net of tax[1] | $(17,662) | $42,197 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our Treasury lock agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2011. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock agreements as those instruments have not yet settled.

| | Treasury Lock Agreements | Commodity Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| Next twelve months | $(1,266) | $(25,900) | $(27,166) |
| Thereafter | 9,967 | (7,536) | 2,431 |
| Total[1] | $ 8,701 | $(33,436) | $(24,735) |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

*Financial Instruments Not Designated as Hedges*

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statement for the three months ended December 31, 2011 and 2010 was an increase (decrease) in revenue of ($2.2) million and $4.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

## 4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the first quarter of fiscal 2012, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2011.

### Quantitative Disclosures

*Financial Instruments*

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and September 30, 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[1] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[2] | December 31, 2011 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 472 | $ — | $ — | $ 472 |
| Nonregulated segment | 33,768 | 256,098 | — | (272,938) | 16,928 |
| Total financial instruments | 33,768 | 256,570 | — | (272,938) | 17,400 |
| Hedged portion of gas stored underground | 77,551 | — | — | — | 77,551 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 1,151 | — | — | 1,151 |
| Registered investment companies | 38,008 | — | — | — | 38,008 |
| Bonds | — | 18,346 | — | — | 18,346 |
| Total available-for-sale securities | 38,008 | 19,497 | — | — | 57,505 |
| Total assets | $149,327 | $276,067 | $ — | $(272,938) | $152,456 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 86,301 | $ — | $ — | $ 86,301 |
| Nonregulated segment | 51,117 | 254,012 | — | (295,022) | 10,107 |
| Total liabilities | $ 51,117 | $340,313 | $ — | $(295,022) | $ 96,408 |

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)(1) | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral(3) | September 30, 2011 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 1,841 | $ — | $ — | $ 1,841 |
| Nonregulated segment | 15,262 | 97,396 | — | (95,156) | 17,502 |
| Total financial instruments | 15,262 | 99,237 | — | (95,156) | 19,343 |
| Hedged portion of gas stored underground | 47,940 | — | — | — | 47,940 |
| Available-for-sale securities | | | | | |
| Money market funds | — | 1,823 | — | — | 1,823 |
| Registered investment companies | 36,444 | — | — | — | 36,444 |
| Bonds | — | 14,366 | — | — | 14,366 |
| Total available-for-sale securities | 36,444 | 16,189 | — | — | 52,633 |
| Total assets | $ 99,646 | $115,426 | $ — | $ (95,156) | $119,916 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 81,118 | $ — | $ — | $ 81,118 |
| Nonregulated segment | 22,091 | 115,617 | — | (123,943) | 13,765 |
| Total liabilities | $ 22,091 | $196,735 | $ — | $(123,943) | $ 94,883 |

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2011, we had $22.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $11.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $10.7 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

| | Amortized Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| | | (In thousands) | | |
| **As of December 31, 2011** | | | | |
| Domestic equity mutual funds | $27,881 | $5,447 | $ — | $33,328 |
| Foreign equity mutual funds | 4,659 | 305 | (284) | 4,680 |
| Bonds | 18,323 | 45 | (22) | 18,346 |
| Money market funds | 1,151 | — | — | 1,151 |
| | $52,014 | $5,797 | $(306) | $57,505 |
| **As of September 30, 2011** | | | | |
| Domestic equity mutual funds | $27,748 | $4,074 | $ — | $31,822 |
| Foreign equity mutual funds | 4,597 | 267 | (242) | 4,622 |
| Bonds | 14,390 | 10 | (34) | 14,366 |
| Money market funds | 1,823 | — | — | 1,823 |
| | $48,558 | $4,351 | $(276) | $52,633 |

At December 31, 2011 and September 30, 2011, our available-for-sale securities included $39.2 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2011 we maintained investments in bonds that have contractual maturity dates ranging from January 2012 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.2 million in an unrealized loss position of $0.3 million as of December 31, 2011. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other than temporary as of December 31, 2011. We also maintained several bonds with a cumulative fair value of $6.5 million in an unrealized loss position of less than $0.1 million as of December 31, 2011. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment grade, we do not consider this impairment to be other than temporary as of December 31, 2011.

*Other Fair Value Measures*

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of December 31, 2011:

| | December 31, 2011 |
|---|---|
| | (In thousands) |
| Carrying Amount | $2,210,262 |
| Fair Value | $2,572,094 |

## 5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur during fiscal 2012.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our consolidated balance sheets at December 31, 2011 and September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Operating revenues | $23,451 | $23,733 |
| Purchased gas cost | 14,951 | 14,897 |
| Gross profit | 8,500 | 8,836 |
| Operating expenses | 4,174 | 4,016 |
| Operating income | 4,326 | 4,820 |
| Other nonoperating expense | (48) | (33) |
| Income from discontinued operations before income taxes | 4,278 | 4,787 |
| Income tax expense | 1,559 | 1,890 |
| Net income | $ 2,719 | $ 2,897 |

The following table presents balance sheet data related to assets held for sale.

| | December 31, 2011 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Net plant, property & equipment | $127,227 | $127,577 |
| Gas stored underground | 14,257 | 11,931 |
| Other current assets | 3,773 | 786 |
| Deferred charges and other assets | 62 | 277 |
| Assets held for sale | $145,319 | $140,571 |
| Accounts payable and accrued liabilities | $ 9,945 | $ 1,917 |
| Other current liabilities | 5,459 | 4,877 |
| Regulatory cost of removal obligation | 10,367 | 10,498 |
| Deferred credits and other liabilities | 1,175 | 1,153 |
| Liabilities held for sale | $ 26,946 | $ 18,445 |

## 6. Debt

The nature and terms of our debt instruments are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes in the terms of our debt instruments during the three months ended December 31, 2011.

### *Long-term debt*

Long-term debt at December 31, 2011 and September 30, 2011 consisted of the following:

| | December 31, 2011 | September 30, 2011 |
|---|---|---|
| | (In thousands) | |
| Unsecured 10% Notes, redeemed December 2011 | $ — | $ 2,303 |
| Unsecured 5.125% Senior Notes, due January 2013 | 250,000 | 250,000 |
| Unsecured 4.95% Senior Notes, due 2014 | 500,000 | 500,000 |
| Unsecured 6.35% Senior Notes, due 2017 | 250,000 | 250,000 |
| Unsecured 8.50% Senior Notes, due 2019 | 450,000 | 450,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Unsecured 5.50% Senior Notes, due 2041 | 400,000 | 400,000 |
| Medium term notes | | |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| Rental property term note due in installments through 2013 | 262 | 262 |
| Total long-term debt | 2,210,262 | 2,212,565 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | (3,938) | (4,014) |
| Current maturities | (131) | (2,434) |
| | $2,206,193 | $2,206,117 |

Our unsecured 10% notes were paid on their maturity date on December 31, 2011, and were not replaced.

***Short-term debt***

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

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $985 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At December 31, 2011 and September 30, 2011, there was $390.0 million and $206.4 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

***Regulated Operations***

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding, including a five-year $750 million unsecured facility, a $25 million unsecured facility and a $10 million revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.2 million at December 31, 2011.

In addition to these third-party facilities, our regulated operations had a $350 million intercompany revolving credit facility with AEH. This facility was replaced on January 1, 2012 with a $500 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

***Nonregulated Operations***

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility, expiring in December 2013, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH. Due to outstanding letters of credit and various covenants, including covenants based on working capital, the amount available to AEM under this credit facility was $110.0 million at December 31, 2011.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

***Shelf Registration***

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At December 31, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

***Debt Covenants***

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2011, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 56 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

AEM is required by the financial covenants in its facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At December 31, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.39 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at December 31, 2011, AEM's net working capital was $118.2 million and its tangible net worth was $147.8 million.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

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

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

We were in compliance with all of our debt covenants as of December 31, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

## 7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2011 and 2010 are calculated as follows:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands, except per share amounts) | |
| **Basic Earnings Per Share from continuing operations** | | |
| Income from continuing operations | $65,788 | $71,100 |
| Less: Income from continuing operations allocated to participating securities | 685 | 748 |
| Income from continuing operations available to common shareholders | $65,103 | $70,352 |
| Basic weighted average shares outstanding | 90,254 | 90,082 |
| Income from continuing operations per share — Basic | $ 0.72 | $ 0.78 |
| **Basic Earnings Per Share from discontinued operations** | | |
| Income from discontinued operations | $ 2,719 | $ 2,897 |
| Less: Income from discontinued operations allocated to participating securities | 28 | 31 |
| Income from discontinued operations available to common shareholders | $ 2,691 | $ 2,866 |
| Basic weighted average shares outstanding | 90,254 | 90,082 |
| Income from discontinued operations per share — Basic | $ 0.03 | $ 0.03 |
| Net income per share — Basic | $ 0.75 | $ 0.81 |
| **Diluted Earnings Per Share from continuing operations** | | |
| Income from continuing operations available to common shareholders | $65,103 | $70,352 |
| Effect of dilutive stock options and other shares | 1 | 2 |
| Income from continuing operations available to common shareholders | $65,104 | $70,354 |
| Basic weighted average shares outstanding | 90,254 | 90,082 |
| Additional dilutive stock options and other shares | 292 | 326 |
| Diluted weighted average shares outstanding | 90,546 | 90,408 |
| Income from continuing operations per share — Diluted | $ 0.72 | $ 0.78 |

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands, except per share amounts) | |
| **Diluted Earnings Per Share from discontinued operations** | | |
| Income from discontinued operations available to common shareholders | $ 2,691 | $ 2,866 |
| Effect of dilutive stock options and other shares | — | — |
| Income from discontinued operations available to common shareholders | $ 2,691 | $ 2,866 |
| Basic weighted average shares outstanding | 90,254 | 90,082 |
| Additional dilutive stock options and other shares | 292 | 326 |
| Diluted weighted average shares outstanding | 90,546 | 90,408 |
| Income from discontinued operations per share — Diluted | $ 0.03 | $ 0.03 |
| Net income per share — Diluted | $ 0.75 | $ 0.81 |

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2011 and 2010 as their exercise price was less than the average market price of the common stock during that period.

***Share Repurchase Program***

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of December 31, 2011, 387,991 shares had been repurchased for an aggregate value of $12.5 million.

## 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 December 31, 2011 and 2010 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

| | Three Months Ended December 31 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 4,298 | $ 4,380 | $4,088 | $3,601 |
| Interest cost | 6,677 | 6,924 | 3,465 | 3,203 |
| Expected return on assets | (5,368) | (5,963) | (652) | (682) |
| Amortization of transition asset | — | — | 378 | 378 |
| Amortization of prior service cost | (35) | (112) | (362) | (362) |
| Amortization of actuarial loss | 4,142 | 3,494 | 662 | 87 |
| Net periodic pension cost | $ 9,714 | $ 8,723 | $7,579 | $6,225 |

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2011 and 2010 are as follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Discount rate | 5.05% | 5.39% | 5.05% | 5.39% |
| Rate of compensation increase | 3.50% | 4.00% | N/A | N/A |
| Expected return on plan assets | 7.75% | 8.25% | 4.70% | 5.00% |

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based upon this valuation, we expect we will be required to contribute between $25 million and $30 million to our pension plans by September 15, 2012.

We contributed $4.8 million to our other post-retirement benefit plans during the three months ended December 31, 2011. We expect to contribute between $20 million and $25 million to these plans during fiscal 2012.

## 9. Commitments and Contingencies

### *Litigation and Environmental Matters*

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2011.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky, *Billy Joe Honeycutt et al. vs. Atmos Energy Corporation, et al.*, which is related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied.

However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals, appealing the verdict of the trial court. The appellees in this case subsequently filed their reply brief with the Court of Appeals on January 16, 2012, with our reply brief due to be filed with the Court by March 16, 2012.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, *Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles*, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. As of this date, the Court has not yet ruled on the motion.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter. However, we continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

***Purchase Commitments***

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2011, AEH was committed to purchase 103.1 Bcf within one year, 35.3 Bcf within one to three years and 0.3 Bcf after three years under indexed contracts. AEH is committed to purchase 3.4 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $2.82 to $6.36 per Mcf. Purchases under these contracts totaled $312.1 million and $334.2 million for the three months ended December 31, 2011 and 2010.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of December 31, 2011 are as follows (in thousands):

| | |
|---|---|
| 2012 | $149,788 |
| 2013 | 82,778 |
| 2014 | 68,124 |
| Thereafter | — |
| | $300,690 |

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes to the estimated storage and transportation fees for the quarter ended December 31, 2011.

***Regulatory Matters***

As previously described in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. Since that time, we have fully cooperated with the Commission during this investigation.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company has paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

As discussed in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in 2010, our Mid-Tex Division agreed to install 100,000 steel service line replacements by September 30, 2012. As of December 31, 2011, we had replaced 60,184 lines and are on schedule for completion in September 2012. Under the terms of the agreement, special rate recovery of the associated return, depreciation and taxes is approved for lines replaced between October 1, 2010 and September 30, 2012. Since October 1, 2010, we have spent $64.0 million on steel service line replacements.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC and SEC have issued a number of rules and regulations, we expect additional rules and regulations to be issued, which should provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation and related rules and regulations. We also anticipate additional reporting and disclosure obligations will be imposed.

As of December 31, 2011, annual rate filing mechanisms were in progress in our Louisiana and Mississippi service areas and there was one other ratemaking activity in progress in our Kansas service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

## 10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, there were no material changes in our concentration of credit risk.

## 11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2011 and 2010 by segment are presented in the following tables:

| | Three Months Ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $693,068 | $19,440 | $388,665 | $ — | $1,101,173 |
| Intersegment revenues | 224 | 37,319 | 55,511 | (93,054) | — |
| | 693,292 | 56,759 | 444,176 | (93,054) | 1,101,173 |
| Purchased gas cost | 402,207 | — | 428,771 | (92,687) | 738,291 |
| Gross profit | 291,085 | 56,759 | 15,405 | (367) | 362,882 |
| Operating expenses | | | | | |
| Operation and maintenance | 93,414 | 16,965 | 6,051 | (368) | 116,062 |
| Depreciation and amortization | 50,831 | 7,651 | 733 | — | 59,215 |
| Taxes, other than income | 38,479 | 3,784 | 935 | — | 43,198 |
| Total operating expenses | 182,724 | 28,400 | 7,719 | (368) | 218,475 |
| Operating income | 108,361 | 28,359 | 7,686 | 1 | 144,407 |
| Miscellaneous income (expense) | (1,756) | (280) | 36 | 125 | (1,875) |
| Interest charges | 27,855 | 7,209 | 252 | 126 | 35,442 |
| Income from continuing operations before income taxes | 78,750 | 20,870 | 7,470 | — | 107,090 |
| Income tax expense | 30,845 | 7,456 | 3,001 | — | 41,302 |
| Income from continuing operations | 47,905 | 13,414 | 4,469 | — | 65,788 |
| Income from discontinued operations, net of tax | 2,719 | — | — | — | 2,719 |
| Net income | $ 50,624 | $13,414 | $ 4,469 | $ — | $ 68,507 |
| Capital expenditures | $128,733 | $24,120 | $ 1,541 | $ — | $ 154,394 |

| | Three Months Ended December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $703,261 | $21,233 | $408,768 | $ — | $1,133,262 |
| Intersegment revenues | 201 | 27,774 | 66,872 | (94,847) | — |
| | 703,462 | 49,007 | 475,640 | (94,847) | 1,133,262 |
| Purchased gas cost | 412,526 | — | 450,462 | (94,450) | 768,538 |
| Gross profit | 290,936 | 49,007 | 25,178 | (397) | 364,724 |
| Operating expenses | | | | | |
| Operation and maintenance | 89,229 | 15,574 | 10,084 | (397) | 114,490 |
| Depreciation and amortization | 47,894 | 5,799 | 1,084 | — | 54,777 |
| Taxes, other than income | 34,448 | 3,553 | 2,167 | — | 40,168 |
| Total operating expenses | 171,571 | 24,926 | 13,335 | (397) | 209,435 |
| Operating income | 119,365 | 24,081 | 11,843 | — | 155,289 |
| Miscellaneous income (expense) | (698) | (282) | 290 | (36) | (726) |
| Interest charges | 29,697 | 8,064 | 1,170 | (36) | 38,895 |
| Income from continuing operations before income taxes | 88,970 | 15,735 | 10,963 | — | 115,668 |
| Income tax expense | 34,549 | 5,633 | 4,386 | — | 44,568 |
| Income from continuing operations | 54,421 | 10,102 | 6,577 | — | 71,100 |
| Income from discontinued operations, net of tax | 2,897 | — | — | — | 2,897 |
| Net income | $ 57,318 | $10,102 | $ 6,577 | $ — | $ 73,997 |
| Capital expenditures | $109,499 | $12,739 | $ 924 | $ — | $ 123,162 |

Balance sheet information at December 31, 2011 and September 30, 2011 by segment is presented in the following tables.

| | December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,328,612 | $ 855,245 | $ 62,356 | $ — | $5,246,213 |
| Investment in subsidiaries | 672,300 | — | (2,096) | (670,204) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 63,031 | — | 22,129 | — | 85,160 |
| Assets from risk management activities | 292 | — | 10,732 | — | 11,024 |
| Other current assets | 912,185 | 13,418 | 453,571 | (214,117) | 1,165,057 |
| Intercompany receivables | 567,587 | — | — | (567,587) | — |
| Total current assets | 1,543,095 | 13,418 | 486,432 | (781,704) | 1,261,241 |
| Intangible assets | — | — | 196 | — | 196 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | 180 | — | 6,196 | — | 6,376 |
| Deferred charges and other assets | 359,860 | 11,297 | 10,449 | — | 381,606 |
| | $7,476,955 | $1,012,341 | $598,244 | $(1,451,908) | $7,635,632 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,267,762 | $ 278,515 | $393,785 | $ (672,300) | $2,267,762 |
| Long-term debt | 2,206,062 | — | 131 | — | 2,206,193 |
| Total capitalization | 4,473,824 | 278,515 | 393,916 | (672,300) | 4,473,955 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | — | — | 131 | — | 131 |
| Short-term debt | 583,980 | — | — | (193,995) | 389,985 |
| Liabilities from risk management activities | 14,521 | — | 4,623 | — | 19,144 |
| Other current liabilities | 606,357 | 11,929 | 170,281 | (18,026) | 770,541 |
| Intercompany payables | — | 531,126 | 36,461 | (567,587) | — |
| Total current liabilities | 1,204,858 | 543,055 | 211,496 | (779,608) | 1,179,801 |
| Deferred income taxes | 813,423 | 181,641 | (13,505) | — | 981,559 |
| Noncurrent liabilities from risk management activities | 70,105 | — | 5,484 | — | 75,589 |
| Regulatory cost of removal obligation | 437,660 | — | — | — | 437,660 |
| Deferred credits and other liabilities | 477,085 | 9,130 | 853 | — | 487,068 |
| | $7,476,955 | $1,012,341 | $598,244 | $(1,451,908) | $7,635,632 |

| | September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,248,198 | $ 838,302 | $ 61,418 | $ — | $5,147,918 |
| Investment in subsidiaries | 670,993 | — | (2,096) | (668,897) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 24,646 | — | 106,773 | — | 131,419 |
| Assets from risk management activities | 843 | — | 17,501 | — | 18,344 |
| Other current assets | 655,716 | 15,413 | 386,215 | (196,154) | 861,190 |
| Intercompany receivables | 569,898 | — | — | (569,898) | — |
| Total current assets | 1,251,103 | 15,413 | 510,489 | (766,052) | 1,010,953 |
| Intangible assets | — | — | 207 | — | 207 |
| Goodwill | 572,908 | 132,381 | 34,711 | — | 740,000 |
| Noncurrent assets from risk management activities | 998 | — | — | — | 998 |
| Deferred charges and other assets | 353,960 | 18,028 | 10,807 | — | 382,795 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,255,421 | $ 265,102 | $405,891 | $ (670,993) | $2,255,421 |
| Long-term debt | 2,205,986 | — | 131 | — | 2,206,117 |
| Total capitalization | 4,461,407 | 265,102 | 406,022 | (670,993) | 4,461,538 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 2,303 | — | 131 | — | 2,434 |
| Short-term debt | 387,691 | — | — | (181,295) | 206,396 |
| Liabilities from risk management activities | 11,916 | — | 3,537 | — | 15,453 |
| Other current liabilities | 474,783 | 10,369 | 170,926 | (12,763) | 643,315 |
| Intercompany payables | — | 543,084 | 26,814 | (569,898) | — |
| Total current liabilities | 876,693 | 553,453 | 201,408 | (763,956) | 867,598 |
| Deferred income taxes | 789,649 | 173,351 | (2,907) | — | 960,093 |
| Noncurrent liabilities from risk management activities | 67,862 | — | 10,227 | — | 78,089 |
| Regulatory cost of removal obligation | 428,947 | — | — | — | 428,947 |
| Deferred credits and other liabilities | 473,602 | 12,218 | 786 | — | 486,606 |
| | $7,098,160 | $1,004,124 | $615,536 | $(1,434,949) | $7,282,871 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2011, the related condensed consolidated statements of income for the three-month periods ended December 31, 2011 and 2010, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2011 and 2010. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2011, 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 22, 2011, 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, 2011, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 8, 2012

**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, 2011.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

## OVERVIEW

Atmos Energy and its subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states.

Through our nonregulated businesses, we provide natural gas management and transportation services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and

Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

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

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the three months ended December 31, 2011.

## RESULTS OF OPERATIONS

We reported net income of $68.5 million, or $0.75 per diluted share for the three months ended December 31, 2011 compared with net income of $74.0 million, or $0.81 per diluted share in the prior-year quarter. Regulated operations contributed 93 percent of our net income during this period with our nonregulated operations contributing the remaining seven percent. Excluding the impact of unrealized margins, diluted earnings per share decreased $0.20 compared with the prior-year quarter. The $0.20 per diluted share decrease primarily reflects the adverse impact of unfavorable natural gas market conditions on our nonregulated segment and increased operating expenses in our natural gas distribution segment. These decreases were partially offset by a five percent increase in consolidated throughput in our regulated transmission and storage segment and the favorable impact of ratemaking efforts in our natural gas distribution segment.

Due to the pending sale of our Missouri, Illinois and Iowa service areas, the results of operations for these three service areas are shown in discontinued operations. During the current-year quarter, discontinued operations generated net income of $2.7 million, or $0.03 per diluted share, compared with net income of $2.9 million, or $0.03 per diluted share in the prior-year quarter. Continuing operations in the current quarter generated net income of $65.8 million, or $0.72 per diluted share, compared with net income of $71.1 million, or $0.78 per diluted share from continuing operations in the prior-year quarter.

The following table presents our consolidated financial highlights for the three months ended December 31, 2011 and 2010:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands, except per share data) | |
| Operating revenues | $1,101,173 | $1,133,262 |
| Gross profit | 362,882 | 364,724 |
| Operating expenses | 218,475 | 209,435 |
| Operating income | 144,407 | 155,289 |
| Miscellaneous expense | (1,875) | (726) |
| Interest charges | 35,442 | 38,895 |
| Income from continuing operations before income taxes | 107,090 | 115,668 |
| Income tax expense | 41,302 | 44,568 |
| Income from continuing operations | 65,788 | 71,100 |
| Income from discontinued operations, net of tax | 2,719 | 2,897 |
| Net income | $ 68,507 | $ 73,997 |
| Diluted net income per share from continuing operations | $ 0.72 | $ 0.78 |
| Diluted net income per share from discontinued operations | 0.03 | 0.03 |
| Diluted net income per share | $ 0.75 | $ 0.81 |

The following table reflects our consolidated net income and diluted earnings per share in our regulated and nonregulated operations:

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $61,319 | $64,523 | $(3,204) |
| Nonregulated operations | 4,469 | 6,577 | (2,108) |
| Net income from continuing operations | 65,788 | 71,100 | (5,312) |
| Net income from discontinued operations | 2,719 | 2,897 | (178) |
| Net income | $68,507 | $73,997 | $(5,490) |
| Diluted EPS from continuing regulated operations | $ 0.67 | $ 0.71 | $ (0.04) |
| Diluted EPS from nonregulated operations | 0.05 | 0.07 | (0.02) |
| Diluted EPS from continuing operations | 0.72 | 0.78 | (0.06) |
| Diluted EPS from discontinued operations | 0.03 | 0.03 | — |
| Consolidated diluted EPS | $ 0.75 | $ 0.81 | $ (0.06) |

### *Three Months Ended December 31, 2011 compared with Three Months Ended December 31, 2010*

#### *Natural Gas Distribution Segment*

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

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for over 90 percent of our residential and commercial meters in the following states for the following time periods:

| | |
|---|---|
| Georgia, Kansas, West Texas | October — May |
| Kentucky, Mississippi, Tennessee, Mid-Tex | November — April |
| Louisiana | December — March |
| Virginia | January — December |

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

In May 2011, we announced that we had entered into a definitive agreement to sell substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

*Review of Financial and Operating Results*

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2011 and 2010 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $291,085 | $290,936 | $ 149 |
| Operating expenses | 182,724 | 171,571 | 11,153 |
| **Operating income** | 108,361 | 119,365 | (11,004) |
| Miscellaneous expense | (1,756) | (698) | (1,058) |
| Interest charges | 27,855 | 29,697 | (1,842) |
| **Income from continuing operations before income taxes** | 78,750 | 88,970 | (10,220) |
| Income tax expense | 30,845 | 34,549 | (3,704) |
| **Income from continuing operations** | 47,905 | 54,421 | (6,516) |
| Income from discontinued operations, net of tax | 2,719 | 2,897 | (178) |
| **Net income** | $ 50,624 | $ 57,318 | $ (6,694) |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 84,890 | 84,137 | 753 |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 32,832 | 32,218 | 614 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 117,722 | 116,355 | 1,367 |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 4,026 | 4,189 | (163) |
| Total consolidated natural gas distribution throughput — MMcf | 121,748 | 120,544 | 1,204 |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.45 | $ 0.49 | $ (0.04) |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 4.78 | $ 4.92 | $ (0.14) |

The $0.1 million increase in natural gas distribution gross profit primarily reflects the following:

- $4.6 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana and Kentucky service areas.
- A two percent rise in transportation volumes resulting in a $0.5 million increase in transportation margins.

These increases were largely offset by the quarter-over-quarter negative effect of the weather normalization adjustment in the Mid-Tex Division, which required utilizing updated weather data in the calculation of the adjustment in the current quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $11.2 million, primarily due to the following:

- $2.9 million increase in depreciation and amortization and a $2.6 million increase in ad valorem taxes associated with an increase in our net plant as a result of our capital investments in the prior year.
- $3.5 million net increase in legal and other administrative costs.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended December 31, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands) | | |
| Mid-Tex | $ 48,449 | $ 57,439 | $ (8,990) |
| Kentucky/Mid-States | 16,318 | 16,853 | (535) |
| Louisiana | 15,201 | 14,961 | 240 |
| West Texas | 10,675 | 9,520 | 1,155 |
| Mississippi | 10,132 | 10,215 | (83) |
| Colorado-Kansas | 8,179 | 7,702 | 477 |
| Other | (593) | 2,675 | (3,268) |
| Total | $108,361 | $119,365 | $(11,004) |

*Recent Ratemaking Developments*

Significant ratemaking developments that occurred during the three months ended December 31, 2011 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a final order from a commission or other governmental authority.

Annual net operating income increases totaling $4.3 million resulting from ratemaking activity became effective in the quarter ended December 31, 2011 as summarized below:

| Rate Action | Annual Increase to Operating Income |
|---|---|
| | (In thousands) |
| Rate case filings | $ 545 |
| Infrastructure programs | 3,744 |
| | $4,289 |

Additionally, the following ratemaking efforts were in progress during the first quarter of fiscal 2012 but had not been completed as of December 31, 2011.

| Division | Rate Action | Jurisdiction | Operating Income Requested |
|---|---|---|---|
| | | | (In thousands) |
| Colorado-Kansas | Ad Valorem[(1)] | Kansas | $ 167 |
| Louisiana | Rate Stabilization Clause | TransLa | — |
| Mississippi | Stable Rate Filing[(2)] | Mississippi | 5,303 |
| | | | $5,470 |

[(1)] The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates. The Kansas Commission approved the filing on January 14, 2012.

[(2)] The Mississippi Commission issued a final order on January 11, 2012 approving a $4.3 million increase to operating income.

Subsequent to December 31, 2011, we filed five rate actions requesting a total increase in annual operating income of $66.8 million in our Mid-Tex, West Texas, Kansas and Georgia service areas. In our Mid-Tex service area, we filed a rate case requesting a $46.0 million annual increase in operating income as well as our first City of Dallas Annual Rate Review filing in which we requested a $2.5 million increase to operating income. In our West Texas and Kansas service areas, we filed rate cases requesting an increase in annual operating income of $11.1 million and $6.1 million. In our Georgia service area, we requested an increase in annual operating income of $1.1 million under the annual pipeline replacement program.

*Rate Case Filings*

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return for our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate case that was completed during the three months ended December 31, 2011.

| Division | State | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|
| | | (In thousands) | |
| *2012 Rate Case Filings:* | | | |
| West Texas — Environs | Texas | $545 | 11/08/2011 |
| Total 2012 Rate Case Filings | | $545 | |

*Infrastructure Programs*

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the three months ended December 31, 2011.

| Division | Period End | Incremental Net Utility Plant Investment | Increase in Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | (In thousands) | (In thousands) | |
| *2012 Infrastructure Programs:* | | | | |
| Kentucky/Mid-States — Georgia | 09/2010 | $ 7,160 | $1,215 | 10/01/2011 |
| Kentucky/Mid-States — Kentucky | 09/2012 | 17,347 | 2,529 | 10/01/2011 |
| Total 2012 Infrastructure Programs | | $24,507 | $3,744 | |

*Annual Rate Filing Mechanism*

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana, Georgia and Mississippi service areas and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division, Georgia rate adjustment mechanism in Kentucky/Mid-States and a rate stabilization clause in the Louisiana Division. There were no annual rate filing mechanisms completed during the three months ended December 31, 2011.

*Other Ratemaking Activity*

There was no other ratemaking activity completed during the three months ended December 31, 2011.

***Regulated Transmission and Storage Segment***

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

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

*Review of Financial and Operating Results*

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2011 and 2010 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | **2011** | **2010** | **Change** |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 37,343 | $ 27,535 | $ 9,808 |
| Third-party transportation | 14,939 | 16,512 | (1,573) |
| Storage and park and lend services | 1,806 | 2,170 | (364) |
| Other | 2,671 | 2,790 | (119) |
| **Gross profit** | 56,759 | 49,007 | 7,752 |
| Operating expenses | 28,400 | 24,926 | 3,474 |
| **Operating income** | 28,359 | 24,081 | 4,278 |
| Miscellaneous expense | (280) | (282) | 2 |
| Interest charges | 7,209 | 8,064 | (855) |
| **Income before income taxes** | 20,870 | 15,735 | 5,135 |
| Income tax expense | 7,456 | 5,633 | 1,823 |
| **Net income** | $ 13,414 | $ 10,102 | $ 3,312 |
| Gross pipeline transportation volumes — MMcf | 160,829 | 153,178 | 7,651 |
| Consolidated pipeline transportation volumes — MMcf | 105,037 | 99,841 | 5,196 |

The $7.8 million increase in regulated transmission and storage gross profit was primarily a result of rate design changes approved in the rate case in the prior year. The current rate design allows us to recover fixed costs associated with transportation and storage services through monthly customer charges rather than through a volumetric charge, which should allow us to earn margin more ratably during the fiscal year. Additionally, consolidated throughput increased about five percent due to increased through-system demand and the execution of new delivery contracts with local producers.

Operating expenses increased $3.5 million primarily due to the following:

- $1.3 million increase due to higher levels of pipeline maintenance activities.
- $1.9 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

***Nonregulated Segment***

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. This business is significantly influenced by competitive factors in the industry, general economic conditions and other factors that could affect the demand for natural gas. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas used to serve those customers. Further, delivered gas margins can be affected by the price of natural gas in the different locations where we buy and sell gas.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions. These margins are influenced by natural gas market conditions including, but not limited to, the price of natural gas, demand for natural gas, the level of domestic natural gas inventory levels and the level of volatility between current (spot) and future natural gas prices. These margins are also impacted by our ability to minimize the demand fees paid to contract for storage capacity.

Higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices may also cause customers to conserve or use alternative energy sources. Lower natural gas prices generally reduce these risks.

The level of volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads and basis differentials from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Conversely, a lack of price volatility reduces opportunities to create value from arbitrage spreads and basis differentials.

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

*Review of Financial and Operating Results*

Financial and operational highlights for our nonregulated segment for the three months ended December 31, 2011 and 2010 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 11,113 | $ 16,041 | $ (4,928) |
| Storage and transportation services | 3,189 | 3,349 | (160) |
| Other | 1,017 | 1,319 | (302) |
| | 15,319 | 20,709 | (5,390) |
| Asset optimization[1] | (21,594) | 3,965 | (25,559) |
| **Total realized margins** | (6,275) | 24,674 | (30,949) |
| **Unrealized margins** | 21,680 | 504 | 21,176 |
| **Gross profit** | 15,405 | 25,178 | (9,773) |
| Operating expenses | 7,719 | 13,335 | (5,616) |
| **Operating income** | 7,686 | 11,843 | (4,157) |
| Miscellaneous income | 36 | 290 | (254) |
| Interest charges | 252 | 1,170 | (918) |
| **Income before income taxes** | 7,470 | 10,963 | (3,493) |
| Income tax expense | 3,001 | 4,386 | (1,385) |
| **Net income** | $ 4,469 | $ 6,577 | $ (2,108) |
| Gross nonregulated delivered gas sales volumes — MMcf | 106,462 | 107,712 | (1,250) |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 90,870 | 94,538 | (3,668) |
| Net physical position (Bcf) | 35.6 | 19.6 | 16.0 |

[1] Net of storage fees of $4.7 million and $3.3 million.

Results for our nonregulated operations during the first fiscal quarter were adversely influenced by continued unfavorable natural gas market conditions. Historically high natural gas storage levels caused by growing domestic natural gas production coupled with an unseasonably warm start to the 2011-2012 winter heating season caused natural gas prices to fall and for spot to forward spread values and basis differentials to remain compressed. Further, unseasonably warm weather reduced the demand for natural gas.

We anticipate natural gas storage levels will remain high for an extended period of time and for unseasonably warm weather to continue during the second quarter of fiscal 2012. Therefore, we expect gas prices to remain relatively low with little volatility and spot to forward spread values and basis differentials to remain compressed. Further, sales of natural gas could be adversely impacted. Accordingly, although we anticipate continuing to profit from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be more consistent with the reduced margins we realized in fiscal 2011 than in previous years.

Realized margins for gas delivery, storage and transportation services and other services were $15.3 million during the three months ended December 31, 2011 compared with $20.7 million for the prior-year quarter. The decrease reflects the following:

- A four percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather particularly in the latter half of the quarter, which reduced sales to our utility, municipal and other weather-sensitive customers. These decreases were partially offset by a 6 percent period-over-period increase in sales to new and existing industrial and power generation customers.

- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.10/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply coupled with increased transportation costs.

Asset optimization margins decreased $25.6 million from the prior-year quarter. In the prior year quarter, due to compressed spot to forward spread values, AEH traded more frequently in the daily cash market and earned intramonth trading gains that exceeded the demand fees paid for its contracted storage capacity.

In the current year quarter, AEH elected to take advantage of falling natural prices by purchasing and injecting a net 15.7 Bcf into storage and capturing incremental physical to forward spread values that should be realized in future periods. As a result of this decision, we realized no storage withdrawal gains to offset the realized losses on the settlement of financial instruments used to hedge our natural gas purchases.

We anticipate this trend will continue during the fiscal second quarter; however, a substantial portion of the incremental margins captured during the quarter are currently anticipated to be realized during the third and fourth quarter of fiscal 2012.

Realized asset optimization margins for the current-year quarter also included a $1.7 million charge to write-down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

The $21.2 million increase in unrealized margins primarily reflects unrealized gains on the financial instruments executed during the quarter to capture incremental physical to forward spreads as a result of falling natural gas prices.

Operating expenses decreased $5.6 million due to the following:

- $3.1 million decrease in insurance and legal costs as a result of the resolution of the FERC matter and the timing of activity pertaining to other litigation.
- $1.4 million decrease in employee related expenses.

Interest charges decreased $0.9 million primarily due to a decrease in commitment fees.

**Liquidity and Capital Resources**

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2012.

**Cash Flows**

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the three months ended December 31, 2011 and 2010 are presented below.

| | Three Months Ended December 31 | | |
|---|---|---|---|
| | 2011 | 2010 | 2011 vs. 2010 |
| | | (In thousands) | |
| Total cash provided by (used in) | | | |
| Operating activities | $ (15,291) | $ 45,824 | $(61,115) |
| Investing activities | (155,474) | (123,532) | (31,942) |
| Financing activities | 124,506 | 75,648 | 48,858 |
| Change in cash and cash equivalents | (46,259) | (2,060) | (44,199) |
| Cash and cash equivalents at beginning of period | 131,419 | 131,952 | (533) |
| Cash and cash equivalents at end of period | $ 85,160 | $ 129,892 | $(44,732) |

*Cash flows from operating activities*

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

The $61.1 million decrease in operating cash flows primarily reflects the effect of purchasing natural gas and injecting it into storage in our nonregulated operations in order to capture incremental value anticipated to be realized in the third and fourth quarter of fiscal 2012, as well as the timing of customer collections and vendor payments.

*Cash flows from investing activities*

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

Capital expenditures for fiscal 2012 are expected to range from $680 million to $700 million. For the three months ended December 31, 2011, capital expenditures were $154.4 million compared with $123.2 million for the three months ended December 31, 2010. The $31.2 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the development of new customer billing and information systems for our natural gas distribution segment.

*Cash flows from financing activities*

The $48.9 million increase in financing cash flows was primarily due to the following:

- $61.3 million additional cash provided from short-term debt borrowings.
- $7.7 million increase in cash flows due to lower repayments of long-term debt. In the current-year quarter, we repaid $2.3 million of long-term debt compared to $10.0 million in the prior-year quarter.

These increases in financing cash flows were partially offset by the following:

- $12.5 million additional cash used to repurchase common stock as part of our share buyback program.
- $7.2 million less cash received from proceeds related to the issuance of common stock.

The following table summarizes our share issuances for the three months ended December 31, 2011 and 2010.

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| Shares issued: | | |
| 1998 Long-Term Incentive Plan | 197,503 | 595,103 |
| Outside Directors Stock-for-Fee Plan | 618 | 638 |
| Total shares issued | 198,121 | 595,741 |

The quarter-over-quarter decrease in the number of shares issued primarily reflects the significant number of stock options exercised in the prior year. During the current quarter, we cancelled and retired 99,555 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares through our 2011 share repurchase program described in Note 7.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our 1998 Long-Term Incentive Plan (LTIP). In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

**Credit Facilities**

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

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.0 billion of working capital funding. As of December 31, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $499.2 million.

**Shelf Registration**

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At December 31, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

### Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of December 31, 2011, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Unsecured senior long-term debt | BBB+ | Baa1 | A- |
| Commercial paper | A-2 | P-2 | F-2 |

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating 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 independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

### Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2011. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

### Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2011, September 30, 2011 and December 31, 2010:

| | December 31, 2011 | | September 30, 2011 | | December 31, 2010 | |
|---|---|---|---|---|---|---|
| | (In thousands, except percentages) | | | | | |
| Short-term debt | $ 389,985 | 8.0% | $ 206,396 | 4.4% | $ 247,993 | 5.3% |
| Long-term debt | 2,206,324 | 45.4% | 2,208,551 | 47.3% | 2,159,753 | 46.1% |
| Shareholders' equity | 2,267,762 | 46.6% | 2,255,421 | 48.3% | 2,274,853 | 48.6% |
| Total | $4,864,071 | 100.0% | $4,670,368 | 100.0% | $4,682,599 | 100.0% |

Total debt as a percentage of total capitalization, including short-term debt, was 53.4 percent at December 31, 2011, 51.7 percent at September 30, 2011 and 51.4 percent at December 31, 2010. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

### Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2011.

### Risk Management Activities

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2011 and 2010:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Fair value of contracts at beginning of period | $(79,277) | $ (49,600) |
| Contracts realized/settled | (17,729) | (32,981) |
| Fair value of new contracts | (555) | 531 |
| Other changes in value | 11,732 | 108,856 |
| Fair value of contracts at end of period | $(85,829) | $ 26,806 |

The fair value of our natural gas distribution segment's financial instruments at December 31, 2011 is presented below by time period and fair value source:

| | Fair Value of Contracts at December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(15,904) | $(69,925) | $— | $— | $(85,829) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(15,904) | $(69,925) | $— | $— | $(85,829) |

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three months ended December 31, 2011 and 2010:

| | Three Months Ended December 31 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Fair value of contracts at beginning of period | $(25,050) | $(12,374) |
| Contracts realized/settled | 17,449 | 934 |
| Fair value of new contracts | — | — |
| Other changes in value | (7,662) | 759 |
| Fair value of contracts at end of period | (15,263) | (10,681) |
| Netting of cash collateral | 22,084 | 25,296 |
| Cash collateral and fair value of contracts at period end | $ 6,821 | $ 14,615 |

The fair value of our nonregulated segment's financial instruments at December 31, 2011 is presented below by time period and fair value source:

| | Fair Value of Contracts at December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(15,975) | $734 | $(22) | $— | $(15,263) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(15,975) | $734 | $(22) | $— | $(15,263) |

## Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2011 and 2010, our total net periodic pension and other benefits cost was $17.3 million and $14.9 million. Those costs relating to our natural gas distribution operations are generally recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates, were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2012 pension and postretirement medical costs for the quarter ended December 31, 2011 were higher than the prior-year quarter.

The amounts with which we fund our defined benefit plans are determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plans when the funding requirements are determined on January 1 of each year. Based upon the most recent evaluation, we anticipate contributing between $25 million and $30 million to our defined benefit plans in fiscal 2012. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing between $20 million and $25 million to these plans during fiscal 2012.

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

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three-month periods ended December 31, 2011 and 2010.

*Natural Gas Distribution Sales and Statistical Data — Continuing Operations*

| | Three Months Ended December 31 | |
|---|---|---|
| | **2011** | **2010** |
| **METERS IN SERVICE, end of period** | | |
| Residential | 2,847,305 | 2,848,433 |
| Commercial | 258,749 | 261,494 |
| Industrial | 2,318 | 2,328 |
| Public authority and other | 10,253 | 10,158 |
| Total meters | 3,118,625 | 3,122,413 |
| **INVENTORY STORAGE BALANCE — Bcf[1]** | 58.1 | 55.6 |
| **SALES VOLUMES — MMcf [2]** | | |
| Gas sales volumes | | |
| Residential | 50,240 | 50,156 |
| Commercial | 26,604 | 26,029 |
| Industrial | 5,412 | 5,146 |
| Public authority and other | 2,634 | 2,806 |
| Total gas sales volumes | 84,890 | 84,137 |
| Transportation volumes | 33,967 | 33,217 |
| Total throughput | 118,857 | 117,354 |
| **OPERATING REVENUES (000's)[2]** | | |
| Gas sales revenues | | |
| Residential | $ 437,509 | $ 443,639 |
| Commercial | 189,688 | 189,265 |
| Industrial | 26,707 | 28,689 |
| Public authority and other | 17,494 | 18,537 |
| Total gas sales revenues | 671,398 | 680,130 |
| Transportation revenues | 14,862 | 15,691 |
| Other gas revenues | 7,032 | 7,641 |
| Total operating revenues | $ 693,292 | $ 703,462 |
| Average transportation revenue per Mcf[1] | $ 0.44 | $ 0.48 |
| Average cost of gas per Mcf sold[1] | $ 4.78 | $ 4.92 |

See footnote following these tables.

*Natural Gas Distribution Sales and Statistical Data — Discontinued Operations*

| | Three Months Ended December 31 | |
|---|---|---|
| | **2011** | **2010** |
| Meters in service, end of period | 84,383 | 83,873 |
| Sales volumes — MMcf | | |
| Total gas sales volumes | 2,429 | 2,653 |
| Transportation volumes | 1,597 | 1,536 |
| Total throughput | 4,026 | 4,189 |
| Operating revenues (000's) | $23,451 | $23,733 |

*Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data*

| | Three Months Ended December 31 | |
|---|---|---|
| | **2011** | **2010** |
| **CUSTOMERS, end of period** | | |
| Industrial | 771 | 749 |
| Municipal | 69 | 62 |
| Other | 516 | 512 |
| Total | 1,356 | 1,323 |
| **NONREGULATED INVENTORY STORAGE BALANCE — Bcf** | 27.9 | 22.1 |
| **REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)** | 160,829 | 153,178 |
| **NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(2)** | 106,462 | 107,712 |
| **OPERATING REVENUES (000's)(2)** | | |
| Regulated transmission and storage | $ 56,759 | $ 49,007 |
| Nonregulated | 444,176 | 475,640 |
| Total operating revenues | $500,935 | $524,647 |

Note to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

## RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, there were no material changes in our quantitative and qualitative disclosures about market risk.

## Item 4. *Controls and Procedures*

### Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

### Item 1. *Legal Proceedings*

During the three months ended December 31, 2011, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

### Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of December 31, 2011, 387,991 shares had been repurchased.

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1, 2011 to October 31, 2011 | — | $ — | — | 5,000,000 |
| November 1, 2011 to November 30, 2011 | 77,818 | 32.51 | 77,818 | 4,922,182 |
| December 1, 2011 to December 31, 2011 | 310,173 | 32.26 | 310,173 | 4,612,009 |
| Total | 387,991 | $32.31 | 387,991 | 4,612,009 |

### Item 6. *Exhibits*

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

## SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: February 8, 2012

## EXHIBITS INDEX
## Item 6

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 10.1 | Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012 | |
| 12 | Computation of ratio of earnings to fixed charges | |
| 15 | Letter regarding unaudited interim financial information | |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications* | |
| 101.INS | XBRL Instance Document** | |
| 101.SCH | XBRL Taxonomy Extension Schema** | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase** | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase** | |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase** | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase** | |

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

# 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, 2011**

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

Number of shares outstanding of each of the issuer's classes of common stock, as of July 29, 2011.

| Class | Shares Outstanding |
|---|---|
| No Par Value | 90,285,306 |

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AOCI | Accumulated other comprehensive income |
| APS | Atmos Pipeline and Storage, LLC |
| Bcf | Billion cubic feet |
| FASB | Financial Accounting Standards Board |
| Fitch | Fitch Ratings, Ltd. |
| GRIP | Gas Reliability Infrastructure Program |
| GSRS | Gas System Reliability Surcharge |
| ISRS | Infrastructure System Replacement Surcharge |
| Mcf | Thousand cubic feet |
| MMcf | Million cubic feet |
| Moody's | Moody's Investors Services, Inc. |
| NYMEX | New York Mercantile Exchange, Inc. |
| PPA | Pension Protection Act of 2006 |
| PRP | Pipeline Replacement Program |
| RRC | Railroad Commission of Texas |
| RRM | Rate Review Mechanism |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| WNA | Weather Normalization Adjustment |

## PART I. FINANCIAL INFORMATION

**Item 1.** ***Financial Statements***

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED BALANCE SHEETS

| | June 30, 2011 | September 30, 2010 |
|---|---|---|
| | (Unaudited) | |
| | (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $6,599,950 | $6,542,318 |
| Less accumulated depreciation and amortization | 1,683,899 | 1,749,243 |
| Net property, plant and equipment | 4,916,051 | 4,793,075 |
| Current assets | | |
| Cash and cash equivalents | 117,429 | 131,952 |
| Accounts receivable, net | 342,092 | 273,207 |
| Gas stored underground | 256,768 | 319,038 |
| Other current assets | 273,459 | 150,995 |
| Total current assets | 989,748 | 875,192 |
| Goodwill and intangible assets | 739,677 | 740,148 |
| Deferred charges and other assets | 347,994 | 355,376 |
| | $6,993,470 | $6,763,791 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2011 — 90,284,722 shares; September 30, 2010 — 90,164,103 shares | $ 451 | $ 451 |
| Additional paid-in capital | 1,730,121 | 1,714,364 |
| Retained earnings | 599,506 | 486,905 |
| Accumulated other comprehensive income (loss) | 5,746 | (23,372) |
| Shareholders' equity | 2,335,824 | 2,178,348 |
| Long-term debt | 2,206,106 | 1,809,551 |
| Total capitalization | 4,541,930 | 3,987,899 |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 312,205 | 266,208 |
| Other current liabilities | 333,643 | 413,640 |
| Short-term debt | — | 126,100 |
| Current maturities of long-term debt | 2,434 | 360,131 |
| Total current liabilities | 648,282 | 1,166,079 |
| Deferred income taxes | 967,607 | 829,128 |
| Regulatory cost of removal obligation | 396,201 | 350,521 |
| Deferred credits and other liabilities | 439,450 | 430,164 |
| | $6,993,470 | $6,763,791 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Three Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $ 407,031 | $ 396,319 |
| Regulated transmission and storage segment | 53,570 | 44,957 |
| Nonregulated segment | 491,285 | 427,405 |
| Intersegment eliminations | (108,271) | (107,376) |
| | 843,615 | 761,305 |
| Purchased gas cost | | |
| Natural gas distribution segment | 206,839 | 204,988 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 477,880 | 415,634 |
| Intersegment eliminations | (107,909) | (106,983) |
| | 576,810 | 513,639 |
| Gross profit | 266,805 | 247,666 |
| Operating expenses | | |
| Operation and maintenance | 112,665 | 111,559 |
| Depreciation and amortization | 56,932 | 51,940 |
| Taxes, other than income | 52,142 | 51,908 |
| Asset impairments | 10,988 | — |
| Total operating expenses | 232,727 | 215,407 |
| Operating income | 34,078 | 32,259 |
| Miscellaneous expense | (1,430) | (798) |
| Interest charges | 35,845 | 37,267 |
| Loss from continuing operations before income taxes | (3,197) | (5,806) |
| Income tax benefit | (1,723) | (1,577) |
| Loss from continuing operations | (1,474) | (4,229) |
| Income from discontinued operations, net of tax ($590 and $700) | 908 | 1,075 |
| Net loss | $ (566) | $ (3,154) |
| Basic earning per share | | |
| Loss per share from continuing operations | $ (0.02) | $ (0.04) |
| Income per share from discontinued operations | 0.01 | 0.01 |
| Net loss per share — basic | $ (0.01) | $ (0.03) |
| Diluted earnings per share | | |
| Loss per share from continuing operations | $ (0.02) | $ (0.04) |
| Income per share from discontinued operations | 0.01 | 0.01 |
| Net loss per share — diluted | $ (0.01) | $ (0.03) |
| Cash dividends per share | $ 0.34 | $ 0.335 |
| Weighted average shares outstanding: | | |
| Basic | 90,127 | 92,648 |
| Diluted | 90,127 | 92,648 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (Unaudited) (In thousands, except per share data) | |
| Operating revenues | | |
| Natural gas distribution segment | $2,187,907 | $2,512,032 |
| Regulated transmission and storage segment | 157,553 | 146,998 |
| Nonregulated segment | 1,550,456 | 1,652,453 |
| Intersegment eliminations | (337,542) | (370,229) |
| | 3,558,374 | 3,941,254 |
| Purchased gas cost | | |
| Natural gas distribution segment | 1,317,775 | 1,657,412 |
| Regulated transmission and storage segment | — | — |
| Nonregulated segment | 1,491,815 | 1,556,746 |
| Intersegment eliminations | (336,413) | (369,017) |
| | 2,473,177 | 2,845,141 |
| Gross profit | 1,085,197 | 1,096,113 |
| Operating expenses | | |
| Operation and maintenance | 341,317 | 348,458 |
| Depreciation and amortization | 167,176 | 156,201 |
| Taxes, other than income | 145,868 | 152,840 |
| Asset impairments | 30,270 | — |
| Total operating expenses | 684,631 | 657,499 |
| Operating income | 400,566 | 438,614 |
| Miscellaneous income (expense) | 24,046 | (905) |
| Interest charges | 112,615 | 115,481 |
| Income from continuing operations before income taxes | 311,997 | 322,228 |
| Income tax expense | 114,211 | 124,199 |
| Income from continuing operations | 197,786 | 198,029 |
| Income from discontinued operations, net of tax ($5,122 and $4,094) | 7,854 | 6,273 |
| Net income | $ 205,640 | $ 204,302 |
| Basic earning per share | | |
| Income per share from continuing operations | $ 2.17 | $ 2.12 |
| Income per share from discontinued operations | 0.09 | 0.07 |
| Net income per share — basic | $ 2.26 | $ 2.19 |
| Diluted earnings per share | | |
| Income per share from continuing operations | $ 2.16 | $ 2.11 |
| Income per share from discontinued operations | 0.09 | 0.07 |
| Net income per share — diluted | $ 2.25 | $ 2.18 |
| Cash dividends per share | $ 1.02 | $ 1.005 |
| Weighted average shares outstanding: | | |
| Basic | 90,233 | 92,513 |
| Diluted | 90,530 | 92,856 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (Unaudited) (In thousands) | |
| Cash Flows From Operating Activities | | |
| Net income | $ 205,640 | $ 204,302 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Asset impairments | 30,270 | — |
| Depreciation and amortization: | | |
| Charged to depreciation and amortization | 171,726 | 160,207 |
| Charged to other accounts | 149 | 116 |
| Deferred income taxes | 115,488 | 186,325 |
| Other | 15,927 | 18,425 |
| Net assets/liabilities from risk management activities | (15,869) | 3,429 |
| Net change in operating assets and liabilities | (3,769) | 21,760 |
| Net cash provided by operating activities | 519,562 | 594,564 |
| Cash Flows From Investing Activities | | |
| Capital expenditures | (390,283) | (362,349) |
| Other, net | (3,373) | (438) |
| Net cash used in investing activities | (393,656) | (362,787) |
| Cash Flows From Financing Activities | | |
| Net decrease in short-term debt | (132,072) | (76,019) |
| Net proceeds from issuance of long-term debt | 394,618 | — |
| Settlement of Treasury lock agreements | 20,079 | — |
| Unwinding of Treasury lock agreements | 27,803 | — |
| Repayment of long-term debt | (360,066) | (66) |
| Cash dividends paid | (93,039) | (93,913) |
| Repurchase of equity awards | (5,300) | (1,173) |
| Issuance of common stock | 7,548 | 8,574 |
| Net cash used in financing activities | (140,429) | (162,597) |
| Net increase (decrease) in cash and cash equivalents | (14,523) | 69,180 |
| Cash and cash equivalents at beginning of period | 131,952 | 111,203 |
| Cash and cash equivalents at end of period | $ 117,429 | $ 180,383 |

See accompanying notes to condensed consolidated financial statements

## ATMOS ENERGY CORPORATION

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
**(Unaudited)**
**June 30, 2011**

### 1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which currently cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

As discussed in Note 11, we operate the Company through the following three segments:

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

### 2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2011 are not indicative of our results of operations for the full 2011 fiscal year, which ends September 30, 2011.

Our earnings have been impacted by several one-time items in the current year, including the following pre-tax amounts:

- $27.8 million gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $19.3 million non-cash impairment of assets in the Ft. Necessity storage project.
- $11.0 million non-cash impairment of certain natural gas gathering assets.
- $5.0 million one-time tax benefit related to the administrative settlement of various income tax positions.

We have evaluated subsequent events from the June 30, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

***Significant accounting policies***

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010.

As a result of discontinued operations, certain prior-year amounts have been reclassified to conform with the current year presentation.

During the second quarter of fiscal 2011, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the nine months ended June 30, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards had no impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the nine months ended June 30, 2011.

In May 2011, the Financial Accounting Standards Board (FASB) issued guidance that will provide a consistent definition of fair value and ensure that fair value measurements and disclosure requirements are similar between U.S. GAAP and International Financial Reporting Standards. This guidance will change certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements and is effective prospectively for the Company for interim and annual periods beginning after December 15, 2011. We currently do not have any recurring Level 3 fair value measurements; accordingly, the adoption of this guidance will not impact our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance related to the presentation of other comprehensive income which will require that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. This guidance is effective retrospectively for the Company for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of this guidance will not impact our financial position, results of operations or cash flows.

***Regulatory assets and liabilities***

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2011 and September 30, 2010 included the following:

| | June 30, 2011 | September 30, 2010 |
|---|---|---|
| | (In thousands) | |
| **Regulatory assets:** | | |
| Pension and postretirement benefit costs | $200,393 | $209,564 |
| Merger and integration costs, net | 6,360 | 6,714 |
| Deferred gas costs | 22,083 | 22,701 |
| Regulatory cost of removal asset | 32,691 | 31,014 |
| Environmental costs | 434 | 805 |
| Rate case costs | 5,321 | 4,505 |
| Deferred franchise fees | 393 | 1,161 |
| Other | 3,940 | 1,046 |
| | $271,615 | $277,510 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 18,739 | $ 43,333 |
| Deferred franchise fees | 629 | — |
| Regulatory cost of removal obligation | 429,354 | 381,474 |
| Other | 9,166 | 6,112 |
| | $457,888 | $430,919 |

The June 30, 2011 amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

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

### *Comprehensive income*

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and nine-month periods ended June 30, 2011 and 2010:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Net income (loss) | $ (566) | $(3,154) | $205,640 | $204,302 |
| Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(56) and $(996) for the three months ended June 30, 2011 and 2010 and of $876 and $(198) for the nine months ended June 30, 2011 and 2010 | (94) | (1,696) | 1,492 | (337) |
| Amortization, unrealized gain and unwinding of interest rate hedging transactions, net of tax expense (benefit) of $(4,629) and $247 for the three months ended June 30, 2011 and 2010 and $7,950 and $743 for the nine month ended June 30, 2011 and 2010 | (7,884) | 422 | 13,536 | 1,265 |
| Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(182) and $5,066 for the three months ended June 30, 2011 and 2010 and $9,008 and $2,999 for the nine months ended June 30, 2011 and 2010 | (285) | 7,921 | 14,090 | 4,690 |
| Comprehensive income (loss) | $(8,829) | $ 3,493 | $234,758 | $209,920 |

Accumulated other comprehensive income (loss), net of tax, as of June 30, 2011 and September 30, 2010 consisted of the following unrealized gains (losses):

| | June 30, 2011 | September 30, 2010 |
|---|---|---|
| | (In thousands) | |
| Accumulated other comprehensive income (loss): | | |
| Unrealized holding gains on investments | $ 5,697 | $ 4,205 |
| Treasury lock agreements | 8,068 | (5,468) |
| Cash flow hedges | (8,019) | (22,109) |
| | $ 5,746 | $(23,372) |

## 3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the third quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

***Regulated Commodity Risk Management Activities***

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the planned winter flowing gas requirements. We have not designated these financial instruments as hedges.

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

***Nonregulated Commodity Risk Management Activities***

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers' request.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 65 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

***Interest Rate Risk Management Activities***

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. This offering is discussed in Note 6. We designated these Treasury locks as cash flow hedges of an anticipated transaction. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks, as well as the Treasury locks discussed above, were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

***Quantitative Disclosures Related to Financial Instruments***

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

As of June 30, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

| Contract Type | Hedge Designation | Natural Gas Distribution | Nonregulated |
|---|---|---|---|
| | | Quantity (MMcf) | |
| Commodity contracts | Fair Value | — | (20,915) |
| | Cash Flow | — | 28,317 |
| | Not designated | 16,340 | 18,140 |
| | | 16,340 | 25,542 |

*Financial Instruments on the Balance Sheet*

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2011 and September 30, 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $15.4 million and $24.9 million of cash held on deposit in margin accounts as of June 30, 2011 and September 30, 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **June 30, 2011** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 11,529 | $ 11,529 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 241 | 241 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | — | (15,930) | (15,930) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (6,237) | (6,237) |
| **Total** | | — | (10,397) | (10,397) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 1,972 | 19,174 | 21,146 |
| Noncurrent commodity contracts | Deferred charges and other assets | 767 | 7,093 | 7,860 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (5,207) | (20,109) | (25,316) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (56) | (7,170) | (7,226) |
| **Total** | | (2,524) | (1,012) | (3,536) |
| **Total Financial Instruments** | | $(2,524) | $(11,409) | $(13,933) |

| | Balance Sheet Location | Natural Gas Distribution | Nonregulated | Total |
|---|---|---|---|---|
| | | | (In thousands) | |
| **September 30, 2010** | | | | |
| **Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | $ — | $ 40,030 | $ 40,030 |
| Noncurrent commodity contracts | Deferred charges and other assets | — | 2,461 | 2,461 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | — | (56,575) | (56,575) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | — | (9,222) | (9,222) |
| **Total** | | — | (23,306) | (23,306) |
| **Not Designated As Hedges:** | | | | |
| **Asset Financial Instruments** | | | | |
| Current commodity contracts | Other current assets | 2,219 | 16,459 | 18,678 |
| Noncurrent commodity contracts | Deferred charges and other assets | 47 | 2,056 | 2,103 |
| **Liability Financial Instruments** | | | | |
| Current commodity contracts | Other current liabilities | (48,942) | (7,178) | (56,120) |
| Noncurrent commodity contracts | Deferred credits and other liabilities | (2,924) | (405) | (3,329) |
| **Total** | | (49,600) | 10,932 | (38,668) |
| **Total Financial Instruments** | | $(49,600) | $(12,374) | $(61,974) |

*Impact of Financial Instruments on the Income Statement*

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $5.8 million and $3.8 million. For the nine months ended June 30, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $23.3 million and $44.2 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

*Fair Value Hedges*

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2011 and 2010 is presented below.

| | Three Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Commodity contracts | $ 7,837 | $(10,525) |
| Fair value adjustment for natural gas inventory designated as the hedged item | (1,781) | 14,678 |
| Total impact on revenue | $ 6,056 | $ 4,153 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 853 | $ (235) |
| Timing ineffectiveness | 5,203 | 4,388 |
| | $ 6,056 | $ 4,153 |

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (In thousands) | |
| Commodity contracts | $ 4,834 | $20,296 |
| Fair value adjustment for natural gas inventory designated as the hedged item | 19,430 | 26,195 |
| Total impact on revenue | $24,264 | $46,491 |
| The impact on revenue is comprised of the following: | | |
| Basis ineffectiveness | $ 1,265 | $ (684) |
| Timing ineffectiveness | 22,999 | 47,175 |
| | $24,264 | $46,491 |

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

*Cash Flow Hedges*

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

| | Three Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(3,907) | $(3,907) |
| Loss arising from ineffective portion of commodity contracts | — | — | (281) | (281) |
| Total impact on revenue | — | — | (4,188) | (4,188) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (614) | — | — | (614) |
| Total Impact from Cash Flow Hedges | $(614) | $ — | $(4,188) | $(4,802) |

| | Three Months Ended June 30, 2010 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(8,523) | $(8,523) |
| Loss arising from ineffective portion of commodity contracts | — | — | (350) | (350) |
| Total impact on revenue | — | — | (8,873) | (8,873) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (669) | — | — | (669) |
| Total Impact from Cash Flow Hedges | $(669) | $ — | $(8,873) | $(9,542) |

| | Nine Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(25,488) | $(25,488) |
| Loss arising from ineffective portion of commodity contracts | — | — | (958) | (958) |
| Total impact on revenue | — | — | (26,446) | (26,446) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (1,953) | — | — | (1,953) |
| Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income | 21,803 | 6,000 | — | 27,803 |
| Total Impact from Cash Flow Hedges | $19,850 | $6,000 | $(26,446) | $ (596) |

| | Nine Months Ended June 30, 2010 | | | |
|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Consolidated |
| | (In thousands) | | | |
| Loss reclassified from AOCI into revenue for effective portion of commodity contracts | $ — | $ — | $(40,196) | $(40,196) |
| Loss arising from ineffective portion of commodity contracts | — | — | (2,307) | (2,307) |
| Total impact on revenue | — | — | (42,503) | (42,503) |
| Loss on settled Treasury lock agreements reclassified from AOCI into interest expense | (2,008) | — | — | (2,008) |
| Total Impact from Cash Flow Hedges | $(2,008) | $ — | $(42,503) | $(44,511) |

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| *Increase (decrease) in fair value:* | | | | |
| Treasury lock agreements | $(8,270) | $ — | $ 29,822 | $ — |
| Forward commodity contracts | (2,668) | 2,722 | (1,457) | (19,829) |
| *Recognition of (gains) losses in earnings due to settlements:* | | | | |
| Treasury lock agreements | 386 | 422 | (16,286) | 1,265 |
| Forward commodity contracts | 2,383 | 5,199 | 15,547 | 24,519 |
| Total other comprehensive income (loss) from hedging, net of tax[1] | $(8,169) | $8,343 | $ 27,626 | $ 5,955 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2011.

| | Treasury Lock Agreements | Commodity Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| Next twelve months | $(1,266) | $(3,905) | $(5,171) |
| Thereafter | 9,334 | (4,114) | 5,220 |
| Total[1] | $ 8,068 | $(8,019) | $ 49 |

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

*Financial Instruments Not Designated as Hedges*

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended June 30, 2011 and 2010 was an increase (decrease) in revenue of $(4.3) million and $0.7 million. For the nine months ended June 30, 2011 and 2010 revenue increased $3.9 million and $13.0 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

## 4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three and nine months ended June 30, 2011, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 8 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2010.

### Quantitative Disclosures

*Financial Instruments*

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2011 and

September 30, 2010. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[1] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[2] | June 30, 2011 |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 2,739 | $ — | $ — | $ 2,739 |
| Nonregulated segment | 3,696 | 34,367 | — | (25,006) | 13,057 |
| Total financial instruments | 3,696 | 37,106 | — | (25,006) | 15,796 |
| Hedged portion of gas stored underground | 86,544 | — | — | — | 86,544 |
| Available-for-sale securities | 44,045 | — | — | — | 44,045 |
| Total assets | $134,285 | $37,106 | $ — | $(25,006) | $146,385 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 5,263 | $ — | $ — | $ 5,263 |
| Nonregulated segment | 10,645 | 38,827 | — | (40,388) | 9,084 |
| Total liabilities | $ 10,645 | $44,090 | $ — | $(40,388) | $ 14,347 |

| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2)[1] | Significant Other Unobservable Inputs (Level 3) | Netting and Cash Collateral[3] | September 30, 2010 |
|---|---|---|---|---|---|
| | | (In thousands) | | | |
| **Assets:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $ 2,266 | $ — | $ — | $ 2,266 |
| Nonregulated segment | 18,544 | 42,462 | — | (41,760) | 19,246 |
| Total financial instruments | 18,544 | 44,728 | — | (41,760) | 21,512 |
| Hedged portion of gas stored underground | 57,507 | — | — | — | 57,507 |
| Available-for-sale securities | 41,466 | — | — | — | 41,466 |
| Total assets | $117,517 | $44,728 | $ — | $(41,760) | $120,485 |
| **Liabilities:** | | | | | |
| Financial instruments | | | | | |
| Natural gas distribution segment | $ — | $51,866 | $ — | $ — | $ 51,866 |
| Nonregulated segment | 41,430 | 31,950 | — | (66,649) | 6,731 |
| Total liabilities | $ 41,430 | $83,816 | $ — | $(66,649) | $ 58,597 |

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are

adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of June 30, 2011, we had $15.4 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $4.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $11.0 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

*Nonrecurring Fair Value Measurements*

As discussed in Note 9, during the third quarter we performed an impairment assessment of certain natural gas gathering assets in our nonregulated segment. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $6 million and recorded a pre-tax noncash impairment loss of approximately $11 million.

*Other Fair Value Measures*

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of June 30, 2011:

| | June 30, 2011 |
|---|---|
| | (In thousands) |
| Carrying Amount | $2,212,630 |
| Fair Value | $2,474,064 |

## 5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for an all cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at June 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Operating revenues | $11,524 | $8,952 | $71,047 | $62,121 |
| Purchased gas cost | 5,460 | 3,390 | 44,993 | 39,836 |
| Gross profit | 6,064 | 5,562 | 26,054 | 22,285 |
| Operating expenses | 4,472 | 3,712 | 12,919 | 11,654 |
| Operating income | 1,592 | 1,850 | 13,135 | 10,631 |
| Other nonoperating expense | (94) | (75) | (159) | (264) |
| Income from discontinued operations before income taxes | 1,498 | 1,775 | 12,976 | 10,367 |
| Income tax expense | 590 | 700 | 5,122 | 4,094 |
| Net income | $ 908 | $1,075 | $ 7,854 | $ 6,273 |

The following table presents balance sheet data related to assets held for sale.

| | June 30, 2011 |
|---|---|
| | (In thousands) |
| Net plant, property & equipment | $126,375 |
| Gas stored underground | 5,938 |
| Other current assets | 431 |
| Deferred charges and other assets | 197 |
| Assets held for sale | $132,941 |
| Accounts payable and accrued liabilities | $ 1,808 |
| Other current liabilities | 5,086 |
| Regulatory cost of removal obligation | 11,435 |
| Deferred credits and other liabilities | 810 |
| Liabilities held for sale | $ 19,139 |

## 6. Debt

### *Long-term debt*

Long-term debt at June 30, 2011 and September 30, 2010 consisted of the following:

| | June 30, 2011 | September 30, 2010 |
|---|---|---|
| | (In thousands) | |
| Unsecured 7.375% Senior Notes, redeemed May 2011 | $ — | $ 350,000 |
| Unsecured 10% Notes, due December 2011 | 2,303 | 2,303 |
| Unsecured 5.125% Senior Notes, due 2013 | 250,000 | 250,000 |
| Unsecured 4.95% Senior Notes, due 2014 | 500,000 | 500,000 |
| Unsecured 6.35% Senior Notes, due 2017 | 250,000 | 250,000 |
| Unsecured 8.50% Senior Notes, due 2019 | 450,000 | 450,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Unsecured 5.50% Senior Notes, due 2041 | 400,000 | — |
| Medium term notes | | |
| Series A, 1995-2, 6.27%, due December 2010 | — | 10,000 |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| Rental property term note due in installments through 2013 | 327 | 393 |
| Total long-term debt | 2,212,630 | 2,172,696 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | (4,090) | (3,014) |
| Current maturities | (2,434) | (360,131) |
| | $2,206,106 | $1,809,551 |

As noted above, our unsecured 10% notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011, using funds drawn from commercial paper. We replaced these senior notes on June 10, 2011 with $400 million 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks discussed in Note 3. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

### *Short-term debt*

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

Prior to the third quarter of fiscal 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. As a result of these changes, we have $975 million of working capital funding from our commercial paper program and three committed revolving credit facilities with third-party lenders.

At June 30, 2011, there were no short-term debt borrowings outstanding. At September 30, 2010, there was a total of $126.1 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

*Regulated Operations*

We fund our regulated operations as needed, primarily through our commercial paper program and two committed revolving credit facilities with third-party lenders that provide approximately $775 million of working capital funding. The first facility is a five-year $750 million unsecured credit facility, expiring May 2016, that bears interest at a base rate or at a LIBOR- based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At June 30, 2011, there were no borrowings under this facility nor was there any commercial paper outstanding.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility was renewed effective April 1, 2011. At June 30, 2011, there were no borrowings outstanding under this facility.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2011, our total-debt-to-total-capitalization ratio, as defined, was 51 percent. In addition, both the interest margin over the Eurodollar rate and the fees that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $173.8 million outstanding under this facility at June 30, 2011.

*Nonregulated Operations*

Atmos Energy Marketing, LLC (AEM), a wholly-owned subsidiary of AEH has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At June 30, 2011, there were no borrowings outstanding under this credit facility. However, at June 30, 2011, AEM letters of credit totaling $24.8 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $125.2 million at June 30, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.34 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at June 30, 2011, AEM's net working capital was $139.5 million and its tangible net worth was $150.9 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at June 30, 2011.

### *Shelf Registration*

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities prior to our $400 million senior notes offering in June 2011. At June 30, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

### *Debt Covenants*

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

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

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB+ and a Moody's rating of Baa1. We have no other triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

We were in compliance with all of our debt covenants as of June 30, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

## 7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and nine months ended June 30, 2011 and 2010 are calculated as follows:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands, except per share amounts) | | | |
| **Basic Earnings Per Share from continuing operations** | | | | |
| Income (loss) from continuing operations | $ (1,474) | $ (4,229) | $197,786 | $198,029 |
| Less: Income (loss) from continuing operations allocated to participating securities | (32) | (51) | 2,076 | 2,018 |
| Income (loss) from continuing operations available to common shareholders | $ (1,442) | $ (4,178) | $195,710 | $196,011 |
| Basic weighted average shares outstanding | 90,127 | 92,648 | 90,233 | 92,513 |
| Income (loss) from continuing operations per share — Basic | $ (0.02) | $ (0.04) | $ 2.17 | $ 2.12 |
| **Basic Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations | $ 908 | $ 1,075 | $ 7,854 | $ 6,273 |
| Less: Income from discontinued operations allocated to participating securities | 20 | 13 | 82 | 64 |
| Income from discontinued operations available to common shareholders | $ 888 | $ 1,062 | $ 7,772 | $ 6,209 |
| Basic weighted average shares outstanding | 90,127 | 92,648 | 90,233 | 92,513 |
| Income from discontinued operations per share — Basic | $ 0.01 | $ 0.01 | $ 0.09 | $ 0.07 |
| Net income (loss) per share — Basic | $ (0.01) | $ (0.03) | $ 2.26 | $ 2.19 |

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands, except per share amounts) | | | |
| **Diluted Earnings Per Share from continuing operations** | | | | |
| Income (loss) from continuing operations available to common shareholders | $(1,442) | $(4,178) | $195,710 | $196,011 |
| Effect of dilutive stock options and other shares | — | — | 4 | 4 |
| Income (loss) from continuing operations available to common shareholders | $(1,442) | $(4,178) | $195,714 | $196,015 |
| Basic weighted average shares outstanding | 90,127 | 92,648 | 90,233 | 92,513 |
| Additional dilutive stock options and other shares | — | — | 297 | 343 |
| Diluted weighted average shares outstanding | 90,127 | 92,648 | 90,530 | 92,856 |
| Income (loss) from continuing operations per share — Diluted | $ (0.02) | $ (0.04) | $ 2.16 | $ 2.11 |
| **Diluted Earnings Per Share from discontinued operations** | | | | |
| Income from discontinued operations available to common shareholders | $ 888 | $ 1,062 | $ 7,772 | $ 6,209 |
| Effect of dilutive stock options and other shares | 2 | — | — | — |
| Income from discontinued operations available to common shareholders | $ 890 | $ 1,062 | $ 7,772 | $ 6,209 |
| Basic weighted average shares outstanding | 90,127 | 92,648 | 90,233 | 92,513 |
| Additional dilutive stock options and other shares | — | — | 297 | 343 |
| Diluted weighted average shares outstanding | 90,127 | 92,648 | 90,530 | 92,856 |
| Income from discontinued operations per share — Diluted | $ 0.01 | $ 0.01 | $ 0.09 | $ 0.07 |
| Net income (loss) per share — Diluted | $ (0.01) | $ (0.03) | $ 2.25 | $ 2.18 |

There were approximately 288,000 and 333,000 stock options and other shares excluded from the computation of diluted earnings per share for the three months ended June 30, 2011 and 2010 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2011 and 2010 as their exercise price was less than the average market price of the common stock during that period.

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received and retired 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

## 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 and nine months ended June 30, 2011 and 2010 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. The curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained unchanged.

| | Three Months Ended June 30 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 4,257 | $ 3,993 | $3,601 | $3,360 |
| Interest cost | 7,055 | 6,524 | 3,204 | 3,018 |
| Expected return on assets | (6,285) | (6,320) | (681) | (615) |
| Amortization of transition asset | — | — | 377 | 377 |
| Amortization of prior service cost | (106) | (193) | (362) | (375) |
| Amortization of actuarial loss | 2,748 | 2,822 | 87 | 93 |
| Net periodic pension cost | $ 7,669 | $ 6,826 | $6,226 | $5,858 |

| | Nine Months Ended June 30 | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Components of net periodic pension cost: | | | | |
| Service cost | $ 12,894 | $ 11,982 | $10,803 | $10,077 |
| Interest cost | 21,034 | 19,569 | 9,610 | 9,051 |
| Expected return on assets | (18,533) | (18,960) | (2,045) | (1,845) |
| Amortization of transition asset | — | — | 1,133 | 1,134 |
| Amortization of prior service cost | (323) | (582) | (1,087) | (1,125) |
| Amortization of actuarial loss | 8,990 | 8,469 | 260 | 282 |
| Curtailment gain | (40) | — | — | — |
| Net periodic pension cost | $ 24,022 | $ 20,478 | $18,674 | $17,574 |

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2011 and 2010 are as follows:

| | Pension Account Plan | | Other Pension Benefits | | Other Benefits | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Discount rate | 5.68% | 5.52% | 5.39% | 5.52% | 5.39% | 5.52% |
| Rate of compensation increase | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Expected return on plan assets | 8.25% | 8.25% | 8.25% | 8.25% | 5.00% | 5.00% |

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we will be required to contribute less than $2 million to our pension plans during fiscal 2011.

We contributed $8.7 million to our other post-retirement benefit plans during the nine months ended June 30, 2011. We expect to contribute a total of approximately $12 million to these plans during fiscal 2011.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

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

| | Amortized Cost | Gross Unrealized Gain | Gross Unrealized Loss | Fair Value |
|---|---|---|---|---|
| | | (In thousands) | | |
| **As of June 30, 2011:** | | | | |
| Domestic equity mutual funds | $27,593 | $7,627 | $ — | $35,220 |
| Foreign equity mutual funds | 4,597 | 1,416 | — | 6,013 |
| Money market funds | 2,812 | — | — | 2,812 |
| | $35,002 | $9,043 | $ — | $44,045 |
| **As of September 30, 2010:** | | | | |
| Domestic equity mutual funds | $29,540 | $5,698 | $ — | $35,238 |
| Foreign equity mutual funds | 4,753 | 976 | — | 5,729 |
| Money market funds | 499 | — | — | 499 |
| | $34,792 | $6,674 | $ — | $41,466 |

## 9. Commitments and Contingencies

### *Litigation and Environmental Matters*

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2011. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict will be overturned on appeal.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued does not reflect the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

***Purchase Commitments***

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2011, AEH was committed to purchase 104.5 Bcf within one year, 52.4 Bcf within one to three years and 2.4 Bcf after three years under indexed contracts. AEH is committed to purchase 2.6 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $4.13 to $6.36 per Mcf. Purchases under these contracts totaled $356.8 million and $315.6 million for the three months ended June 30, 2011 and 2010 and $1,130.0 million and $1,208.4 million for the nine months ended June 30, 2011 and 2010.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2011 are as follows (in thousands):

| | |
|---|---|
| 2011 | $ 52,703 |
| 2012 | 307,694 |
| 2013 | 112,319 |
| 2014 | 86,994 |
| 2015 | — |
| Thereafter | — |
| | $559,710 |

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2011.

***Regulatory Matters***

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. There have been no material developments in this matter during the nine months ended June 30, 2011. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 25,311 lines for a cost of $34.0 million as of June 30, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

As of June 30, 2011, administrative reviews of our rate review mechanisms in our Mid-Tex and West Texas service areas were in progress and a gas reliability infrastructure program (GRIP) filing was in progress in our Atmos Pipeline — Texas service area. In addition, there were other ratemaking activities in progress in our Kentucky/Mid-States, West Texas and Louisiana service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments* and *Regulated Transmission and Storage Segment.*

### *Other Matters*

AGC owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we are to be paid from future production generated from the assets.

As noted above, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, we performed an impairment assessment of these assets during the third fiscal quarter and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value based on the results of a weighted average discounted cash flow analysis and recorded a pretax noncash impairment loss of $11.0 million.

As we previously discussed in Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

## 10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the nine months ended June 30, 2011, there were no material changes in our concentration of credit risk.

## 11. Segment Information

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine month periods ended June 30, 2011 and 2010 by segment are presented in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

| | Three Months Ended June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $406,817 | $19,772 | $417,026 | $ — | $843,615 |
| Intersegment revenues | 214 | 33,798 | 74,259 | (108,271) | — |
| | 407,031 | 53,570 | 491,285 | (108,271) | 843,615 |
| Purchased gas cost | 206,839 | — | 477,880 | (107,909) | 576,810 |
| Gross profit | 200,192 | 53,570 | 13,405 | (362) | 266,805 |
| Operating expenses | | | | | |
| Operation and maintenance | 86,804 | 18,786 | 7,437 | (362) | 112,665 |
| Depreciation and amortization | 49,099 | 6,790 | 1,043 | — | 56,932 |
| Taxes, other than income | 47,534 | 3,729 | 879 | — | 52,142 |
| Asset impairments | — | — | 10,988 | — | 10,988 |
| Total operating expenses | 183,437 | 29,305 | 20,347 | (362) | 232,727 |
| Operating income (loss) | 16,755 | 24,265 | (6,942) | — | 34,078 |
| Miscellaneous income (expense) | (1,153) | (312) | 168 | (133) | (1,430) |
| Interest charges | 28,042 | 7,653 | 283 | (133) | 35,845 |
| Income (loss) from continuing operations before income taxes | (12,440) | 16,300 | (7,057) | — | (3,197) |
| Income tax expense (benefit) | (4,311) | 5,748 | (3,160) | — | (1,723) |
| Income (loss) from continuing operations | (8,129) | 10,552 | (3,897) | — | (1,474) |
| Income from discontinued operations, net of tax | 908 | — | — | — | 908 |
| Net income (loss) | $ (7,221) | $10,552 | $ (3,897) | $ — | $ (566) |
| Capital expenditures | $121,452 | $20,239 | $ 1,929 | $ — | $143,620 |

| | Three Months Ended June 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $396,097 | $22,796 | $342,412 | $ — | $761,305 |
| Intersegment revenues | 222 | 22,161 | 84,993 | (107,376) | — |
| | 396,319 | 44,957 | 427,405 | (107,376) | 761,305 |
| Purchased gas cost | 204,988 | — | 415,634 | (106,983) | 513,639 |
| Gross profit | 191,331 | 44,957 | 11,771 | (393) | 247,666 |
| Operating expenses | | | | | |
| Operation and maintenance | 87,323 | 16,050 | 8,579 | (393) | 111,559 |
| Depreciation and amortization | 45,633 | 5,171 | 1,136 | — | 51,940 |
| Taxes, other than income | 47,946 | 3,010 | 952 | — | 51,908 |
| Total operating expenses | 180,902 | 24,231 | 10,667 | (393) | 215,407 |
| Operating income | 10,429 | 20,726 | 1,104 | — | 32,259 |
| Miscellaneous income (expense) | (72) | 94 | 511 | (1,331) | (798) |
| Interest charges | 29,019 | 7,667 | 1,912 | (1,331) | 37,267 |
| Income (loss) from continuing operations before income taxes | (18,662) | 13,153 | (297) | — | (5,806) |
| Income tax expense (benefit) | (6,685) | 4,688 | 420 | — | (1,577) |
| Income (loss) from continuing operations | (11,977) | 8,465 | (717) | — | (4,229) |
| Income from discontinued operations, net of tax | 1,075 | — | — | — | 1,075 |
| Net income (loss) | $ (10,902) | $ 8,465 | $ (717) | $ — | $ (3,154) |
| Capital expenditures | $106,394 | $22,964 | $ 362 | $ — | $129,720 |

| | Nine Months Ended June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $2,187,256 | $ 62,602 | $1,308,516 | $ — | $3,558,374 |
| Intersegment revenues | 651 | 94,951 | 241,940 | (337,542) | — |
| | 2,187,907 | 157,553 | 1,550,456 | (337,542) | 3,558,374 |
| Purchased gas cost | 1,317,775 | — | 1,491,815 | (336,413) | 2,473,177 |
| Gross profit | 870,132 | 157,553 | 58,641 | (1,129) | 1,085,197 |
| Operating expenses | | | | | |
| Operation and maintenance | 268,299 | 49,591 | 24,556 | (1,129) | 341,317 |
| Depreciation and amortization | 145,548 | 18,387 | 3,241 | — | 167,176 |
| Taxes, other than income | 132,070 | 11,395 | 2,403 | — | 145,868 |
| Asset impairments | — | — | 30,270 | — | 30,270 |
| Total operating expenses | 545,917 | 79,373 | 60,470 | (1,129) | 684,631 |
| Operating income (loss) | 324,215 | 78,180 | (1,829) | — | 400,566 |
| Miscellaneous income | 18,305 | 5,267 | 764 | (290) | 24,046 |
| Interest charges | 87,344 | 23,802 | 1,759 | (290) | 112,615 |
| Income (loss) from continuing operations before income taxes | 255,176 | 59,645 | (2,824) | — | 311,997 |
| Income tax expense (benefit) | 94,323 | 21,252 | (1,364) | — | 114,211 |
| Income (loss) from continuing operations | 160,853 | 38,393 | (1,460) | — | 197,786 |
| Income from discontinued operations, net of tax | 7,854 | — | — | — | 7,854 |
| Net income (loss) | $ 168,707 | $ 38,393 | $ (1,460) | $ — | $ 205,640 |
| Capital expenditures | $ 340,713 | $ 44,796 | $ 4,774 | $ — | $ 390,283 |

| | Nine Months Ended June 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| Operating revenues from external parties | $2,511,350 | $ 64,281 | $1,365,623 | $ — | $3,941,254 |
| Intersegment revenues | 682 | 82,717 | 286,830 | (370,229) | — |
| | 2,512,032 | 146,998 | 1,652,453 | (370,229) | 3,941,254 |
| Purchased gas cost | 1,657,412 | — | 1,556,746 | (369,017) | 2,845,141 |
| Gross profit | 854,620 | 146,998 | 95,707 | (1,212) | 1,096,113 |
| Operating expenses | | | | | |
| Operation and maintenance | 266,847 | 53,877 | 28,946 | (1,212) | 348,458 |
| Depreciation and amortization | 137,580 | 15,395 | 3,226 | — | 156,201 |
| Taxes, other than income | 140,234 | 9,226 | 3,380 | — | 152,840 |
| Total operating expenses | 544,661 | 78,498 | 35,552 | (1,212) | 657,499 |
| Operating income | 309,959 | 68,500 | 60,155 | — | 438,614 |
| Miscellaneous income (expense) | 1,474 | 117 | 1,524 | (4,020) | (905) |
| Interest charges | 87,877 | 23,589 | 8,035 | (4,020) | 115,481 |
| Income from continuing operations before income taxes | 223,556 | 45,028 | 53,644 | — | 322,228 |
| Income tax expense | 86,552 | 16,039 | 21,608 | — | 124,199 |
| Income from continuing operations | 137,004 | 28,989 | 32,036 | — | 198,029 |
| Income from discontinued operations, net of tax | 6,273 | — | — | — | 6,273 |
| Net income | $ 143,277 | $ 28,989 | $ 32,036 | $ — | $ 204,302 |
| Capital expenditures | $ 302,621 | $ 56,786 | $ 2,942 | $ — | $ 362,349 |

Balance sheet information at June 30, 2011 and September 30, 2010 by segment is presented to reflect our business structure as of June 30, 2011 in the following tables. Prior-year amounts have been restated accordingly.

| | June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $4,085,081 | $771,777 | $ 59,193 | $ — | $4,916,051 |
| Investment in subsidiaries | 671,885 | — | (2,096) | (669,789) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 39,446 | — | 77,983 | — | 117,429 |
| Assets from risk management activities | 1,972 | — | 13,041 | — | 15,013 |
| Other current assets | 565,265 | 15,822 | 469,576 | (193,357) | 857,306 |
| Intercompany receivables | 505,709 | — | — | (505,709) | — |
| Total current assets | 1,112,392 | 15,822 | 560,600 | (699,066) | 989,748 |
| Intangible assets | — | — | 363 | — | 363 |
| Goodwill | 572,262 | 132,341 | 34,711 | — | 739,314 |
| Noncurrent assets from risk management activities | 767 | — | 16 | — | 783 |
| Deferred charges and other assets | 319,019 | 16,137 | 12,055 | — | 347,211 |
| | $6,761,406 | $936,077 | $664,842 | $(1,368,855) | $6,993,470 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,335,824 | $251,080 | $420,805 | $ (671,885) | $2,335,824 |
| Long-term debt | 2,205,910 | — | 196 | — | 2,206,106 |
| Total capitalization | 4,541,734 | 251,080 | 421,001 | (671,885) | 4,541,930 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 2,303 | — | 131 | — | 2,434 |
| Short-term debt | 173,845 | — | — | (173,845) | — |
| Liabilities from risk management activities | 5,207 | — | 2,995 | — | 8,202 |
| Other current liabilities | 419,848 | 8,862 | 226,352 | (17,416) | 637,646 |
| Intercompany payables | — | 503,857 | 1,852 | (505,709) | — |
| Total current liabilities | 601,203 | 512,719 | 231,330 | (696,970) | 648,282 |
| Deferred income taxes | 798,433 | 163,540 | 5,634 | — | 967,607 |
| Noncurrent liabilities from risk management activities | 56 | — | 6,089 | — | 6,145 |
| Regulatory cost of removal obligation | 396,201 | — | — | — | 396,201 |
| Deferred credits and other liabilities | 423,779 | 8,738 | 788 | — | 433,305 |
| | $6,761,406 | $936,077 | $664,842 | $(1,368,855) | $6,993,470 |

| | September 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Natural Gas Distribution | Regulated Transmission and Storage | Nonregulated | Eliminations | Consolidated |
| | | | (In thousands) | | |
| **ASSETS** | | | | | |
| Property, plant and equipment, net | $3,959,112 | $748,947 | $ 85,016 | $ — | $4,793,075 |
| Investment in subsidiaries | 620,863 | — | (2,096) | (618,767) | — |
| Current assets | | | | | |
| Cash and cash equivalents | 31,952 | — | 100,000 | — | 131,952 |
| Assets from risk management activities | 2,219 | — | 18,356 | — | 20,575 |
| Other current assets | 528,655 | 19,504 | 325,348 | (150,842) | 722,665 |
| Intercompany receivables | 546,313 | — | — | (546,313) | — |
| Total current assets | 1,109,139 | 19,504 | 443,704 | (697,155) | 875,192 |
| Intangible assets | — | — | 834 | — | 834 |
| Goodwill | 572,262 | 132,341 | 34,711 | — | 739,314 |
| Noncurrent assets from risk management activities | 47 | — | 890 | — | 937 |
| Deferred charges and other assets | 324,707 | 13,037 | 16,695 | — | 354,439 |
| | $6,586,130 | $913,829 | $579,754 | $(1,315,922) | $6,763,791 |
| **CAPITALIZATION AND LIABILITIES** | | | | | |
| Shareholders' equity | $2,178,348 | $212,687 | $408,176 | $ (620,863) | $2,178,348 |
| Long-term debt | 1,809,289 | — | 262 | — | 1,809,551 |
| Total capitalization | 3,987,637 | 212,687 | 408,438 | (620,863) | 3,987,899 |
| Current liabilities | | | | | |
| Current maturities of long-term debt | 360,000 | — | 131 | — | 360,131 |
| Short-term debt | 258,488 | — | — | (132,388) | 126,100 |
| Liabilities from risk management activities | 48,942 | — | 731 | — | 49,673 |
| Other current liabilities | 473,076 | 10,949 | 162,508 | (16,358) | 630,175 |
| Intercompany payables | — | 543,007 | 3,306 | (546,313) | — |
| Total current liabilities | 1,140,506 | 553,956 | 166,676 | (695,059) | 1,166,079 |
| Deferred income taxes | 691,126 | 142,337 | (4,335) | — | 829,128 |
| Noncurrent liabilities from risk management activities | 2,924 | — | 6,000 | — | 8,924 |
| Regulatory cost of removal obligation | 350,521 | — | — | — | 350,521 |
| Deferred credits and other liabilities | 413,416 | 4,849 | 2,975 | — | 421,240 |
| | $6,586,130 | $913,829 | $579,754 | $(1,315,922) | $6,763,791 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2011, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2011 and 2010, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2011 and 2010. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation as of September 30, 2010, 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 12, 2010, 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, 2010, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
August 4, 2011

**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, 2010.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

## OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas currently located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

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

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2011.

## RESULTS OF OPERATIONS

Due to the seasonality of our distribution business, we typically incur a net loss in our fiscal third quarter. For the three months ended June 30, 2011, we reported a net loss of $0.6 million, or $0.01 per diluted share compared to a net loss of $3.2 million, or $0.03 per diluted share in the prior-year quarter. The net loss for the three months ended June 30, 2011 includes noncash, unrealized net gains of $0.1 million, or $0.00 per diluted share compared with net losses of $11.1 million, or $0.12 per diluted share for the three months ended June 30, 2010. The net loss for the third quarter includes the impact of the non-cash impairment charge related to Atmos Gathering System assets, totaling $6.1 million or $0.06 per diluted share.

Excluding the impact of unrealized margins and one-time items, diluted earnings per share decreased from income of $0.09 per diluted share in the prior-year quarter to income of $0.05 per diluted share in the current-year quarter, primarily due a decrease in asset optimization margins in our nonregulated segment, partially offset by rate increases in our natural gas distribution and regulated transmission and storage segments.

During the current quarter, we announced the sale of our natural gas distribution operations in our Missouri, Illinois and Iowa service areas. Due to the pending sales transaction, the results of operations for these three service areas are shown in discontinued operations. During the current-year quarter, discontinued operations generated net income of $0.9 million, or $0.01 per diluted share, compared with net income of $1.1 million, or $0.01 per diluted share in the prior-year quarter. Continuing operations in the current quarter generated a net loss of $1.5 million or $0.02 per diluted share, compared with a net loss of $4.2 million or $0.04 per diluted share from continuing operations in the prior-year quarter.

We reported net income of $205.6 million, or $2.25 per diluted share for the nine months ended June 30, 2011, compared with net income of $204.3 million or $2.18 per diluted share in the prior-year period. Income from continuing operations was $197.8 million, or $2.16 per diluted share compared with $198.0 million, or $2.11 per diluted share in the prior-year period. Income from discontinued operations was $7.9 million or $0.09 per diluted share for the year-to-date period, compared with $6.3 million or $0.07 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current period reduced net income by $1.4 million or $0.02 per diluted share compared with net losses recorded in the prior-year period of $6.2 million, or $0.07 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In the prior year-to-date period, net income included the net positive impact of a state sales tax refund of $4.5 million, or $0.05 per diluted share. In the current year-to-date period, net income includes the net positive impact of several one-time items totaling $6.5 million, or $0.07 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.

- $30.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.

- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

On June 10, 2011 we issued $400 million of 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to the settlement of the $300 million Treasury locks associated with the offering. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

During the nine months ended June 30, 2011, we executed on our strategy to streamline our credit facilities, as follows.

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.

- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and certain regulatory restrictions; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

After giving effect to these changes, we now have $975 million of liquidity available to us from our commercial paper program and three committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2011 and 2010:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands, except per share data) | | | |
| Operating revenues | $843,615 | $761,305 | $3,558,374 | $3,941,254 |
| Gross profit | 266,805 | 247,666 | 1,085,197 | 1,096,113 |
| Operating expenses | 232,727 | 215,407 | 684,631 | 657,499 |
| Operating income | 34,078 | 32,259 | 400,566 | 438,614 |
| Miscellaneous income (expense) | (1,430) | (798) | 24,046 | (905) |
| Interest charges | 35,845 | 37,267 | 112,615 | 115,481 |
| Income (loss) from continuing operations before income taxes | (3,197) | (5,806) | 311,997 | 322,228 |
| Income tax expense (benefit) | (1,723) | (1,577) | 114,211 | 124,199 |
| Income (loss) from continuing operations | (1,474) | (4,229) | 197,786 | 198,029 |
| Income (loss) from discontinued operations, net of tax | 908 | 1,075 | 7,854 | 6,273 |
| Net income (loss) | $ (566) | $ (3,154) | $ 205,640 | $ 204,302 |
| Diluted net income (loss) per share from continuing operations | $ (0.02) | $ (0.04) | $ 2.16 | $ 2.11 |
| Diluted net income per share from discontinued operations | 0.01 | 0.01 | 0.09 | 0.07 |
| Diluted net income (loss) per share | $ (0.01) | $ (0.03) | $ 2.25 | $ 2.18 |

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

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $ 2,423 | $(3,512) | $ 5,935 |
| Nonregulated operations | (3,897) | (717) | (3,180) |
| Net loss from continuing operations | (1,474) | (4,229) | 2,755 |
| Net income from discontinued operations | 908 | 1,075 | (167) |
| Net loss | $ (566) | $(3,154) | $ 2,588 |
| Diluted EPS from continuing regulated operations | $ 0.02 | $ (0.03) | $ 0.05 |
| Diluted EPS from nonregulated operations | (0.04) | (0.01) | (0.03) |
| Diluted EPS from continuing operations | (0.02) | (0.04) | 0.02 |
| Diluted EPS from discontinued operations | 0.01 | 0.01 | — |
| Consolidated diluted EPS | $ (0.01) | $ (0.03) | $ 0.02 |

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, except per share data) | | |
| Regulated operations | $199,246 | $165,993 | $ 33,253 |
| Nonregulated operations | (1,460) | 32,036 | (33,496) |
| Net income from continuing operations | 197,786 | 198,029 | (243) |
| Net income from discontinued operations | 7,854 | 6,273 | 1,581 |
| Net income | $205,640 | $204,302 | $ 1,338 |
| Diluted EPS from continuing regulated operations | $ 2.18 | $ 1.77 | $ 0.41 |
| Diluted EPS from nonregulated operations | (0.02) | 0.34 | (0.36) |
| Diluted EPS from continuing operations | 2.16 | 2.11 | 0.05 |
| Diluted EPS from discontinued operations | 0.09 | 0.07 | 0.02 |
| Consolidated diluted EPS | $ 2.25 | $ 2.18 | $ 0.07 |

***Natural Gas Distribution Segment***

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

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

| | |
|---|---|
| Georgia, Kansas, West Texas | October — May |
| Kentucky, Mississippi, Tennessee, Mid-Tex | November — April |
| Louisiana | December — March |
| Virginia | January — December |

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

***Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010***

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2011 and 2010 are presented below.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $200,192 | $191,331 | $ 8,861 |
| Operating expenses | 183,437 | 180,902 | 2,535 |
| **Operating income** | 16,755 | 10,429 | 6,326 |
| Miscellaneous expense | (1,153) | (72) | (1,081) |
| Interest charges | 28,042 | 29,019 | (977) |
| **Loss from continuing operations before income taxes** | (12,440) | (18,662) | 6,222 |
| Income tax benefit | (4,311) | (6,685) | 2,374 |
| **Loss from continuing operations** | (8,129) | (11,977) | 3,848 |
| Income from discontinued operations, net of tax | 908 | 1,075 | (167) |
| **Net loss** | $ (7,221) | $ (10,902) | $ 3,681 |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 37,011 | 35,613 | 1,398 |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 29,955 | 27,956 | 1,999 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 66,966 | 63,569 | 3,397 |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 2,128 | 2,359 | (231) |
| Total consolidated natural gas distribution throughput — MMcf | 69,094 | 65,928 | 3,166 |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.46 | $ 0.46 | $ — |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 5.59 | $ 5.73 | $ (0.14) |

The following table shows our operating income (loss) from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended June 30, 2011 and 2010. The presentation of our natural gas distribution operating income (loss) is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | | (In thousands) | |
| Mid-Tex | $ 759 | $ (2,179) | $ 2,938 |
| Kentucky/Mid-States | 4,832 | 3,344 | 1,488 |
| Louisiana | 6,779 | 6,537 | 242 |
| West Texas | 605 | (104) | 709 |
| Colorado-Kansas | 3,304 | 1,623 | 1,681 |
| Mississippi | (615) | 950 | (1,565) |
| Other | 1,091 | 258 | 833 |
| Total | $16,755 | $10,429 | $ 6,326 |

The $8.9 million increase in natural gas distribution gross profit was primarily due to the following:

- $7.5 million net increase in rate adjustments, primarily in the Mid-Tex, Kentucky and Kansas service areas.
- $1.2 million increase in consolidated throughput due to a five percent increase in consolidated distribution throughput, primarily from higher consumption.
- $1.5 million decrease due to lower revenue-related taxes, offset by a decrease in taxes, other than income.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $2.5 million due primarily to a $3.5 million increase in depreciation and amortization expense, partially offset by $1.4 million lower employee expenses.

*Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010*

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2011 and 2010 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Gross profit** | $870,132 | $854,620 | $ 15,512 |
| Operating expenses | 545,917 | 544,661 | 1,256 |
| **Operating income** | 324,215 | 309,959 | 14,256 |
| Miscellaneous income | 18,305 | 1,474 | 16,831 |
| Interest charges | 87,344 | 87,877 | (533) |
| **Income from continuing operations before income taxes** | 255,176 | 223,556 | 31,620 |
| Income tax expense | 94,323 | 86,552 | 7,771 |
| **Income from continuing operations** | 160,853 | 137,004 | 23,849 |
| Income from discontinued operations, net of tax | 7,854 | 6,273 | 1,581 |
| **Net income** | $168,707 | $143,277 | $ 25,430 |
| Consolidated natural gas distribution sales volumes from continuing operations — MMcf | 253,665 | 285,996 | (32,331) |
| Consolidated natural gas distribution transportation volumes from continuing operations — MMcf | 99,551 | 98,442 | 1,109 |
| Consolidated natural gas distribution throughput from continuing operations — MMcf | 353,216 | 384,438 | (31,222) |
| Consolidated natural gas distribution throughput from discontinued operations — MMcf | 12,723 | 13,835 | (1,112) |
| Total consolidated natural gas distribution throughput — MMcf | 365,939 | 398,273 | (32,334) |
| Consolidated natural gas distribution average transportation revenue per Mcf | $ 0.47 | $ 0.46 | $ 0.01 |
| Consolidated natural gas distribution average cost of gas per Mcf sold | $ 5.21 | $ 5.77 | $ (0.56) |

The following table shows our operating income from continuing operations by natural gas distribution division, in order of rate base, for the nine months ended June 30, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands) | | |
| Mid-Tex | $140,674 | $128,045 | $12,629 |
| Kentucky/Mid-States | 50,522 | 43,791 | 6,731 |
| Louisiana | 44,975 | 42,775 | 2,200 |
| West Texas | 29,405 | 33,053 | (3,648) |
| Colorado-Kansas | 26,256 | 24,071 | 2,185 |
| Mississippi | 27,604 | 28,604 | (1,000) |
| Other | 4,779 | 9,620 | (4,841) |
| Total | $324,215 | $309,959 | $14,256 |

The $15.5 million increase in natural gas distribution gross profit primarily reflects a $35.8 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky, Kansas and Georgia service areas.

These increases were partially offset by:

- $11.2 million decrease due to an eight percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.
- $8.5 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $1.3 million, primarily due to the following:

- $7.4 million increase due to the absence of a state sales tax refund received in the prior year.
- $8.0 million increase in depreciation and amortization expense.
- $1.2 million increase in vehicles and equipment expense.

These increases were partially offset by:

- $8.2 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.8 million decrease in employee-related expenses.

Net income for this segment for the year-to-date period was also favorably impacted by a $21.8 million gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

*Recent Ratemaking Developments*

Significant ratemaking developments that occurred during the nine months ended June 30, 2011 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $28.1 million resulting from ratemaking activity became effective in the nine months ended June 30, 2011 as summarized below:

| Rate Action | Annual Increase to Operating Income |
|---|---|
| | (In thousands) |
| GRIP filings | $ 919 |
| Annual rate filing mechanisms | 25,070 |
| Other rate activity | 2,075 |
| | $28,064 |

Additionally, the following ratemaking efforts were in progress during the third quarter of fiscal 2011 but had not been completed as of June 30, 2011.

| Division | Rate Action | Jurisdiction | Operating Income Requested |
|---|---|---|---|
| | | | (In thousands) |
| Kentucky/Mid-States | PRP[(1)] | Georgia | $ 1,192 |
| Louisiana | LGS RSC[(2)] | Louisiana | 4,600 |
| Mid-Tex | Rate Review Mechanism (RRM)[(3)] | Settled Cities[(4)] | 13,152 |
| West Texas | Environs Rate Case[(5)] | Amarillo | 78 |
| | RRM | Lubbock | 2,136 |
| | RRM[(6)] | WT Cities | 2,552 |
| | Special Contract | Triangle | 641 |
| | | | $24,351 |

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Louisiana Commission Staff recommended an increase of $4.1 million effective July 1, 2011, which the Commission accepted.

(3) The amount requested represents an increase of $7.7 million under the RRM and $5.5 million related to year two of our steel service line program. In July 2011, the Company and representatives of the Settled Cities agreed to no change in operating income under the RRM and an operating income increase of $5.5 million related to the steel service line program to be implemented on September 1, 2011.

(4) Represents 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.

(5) The Railroad Commission of Texas (RRC) approved the requested increase in operating income on July 26, 2011.

(6) On August 1, 2011, the Company and representatives of the West Texas Cities agreed to resolve the 2010 RRM with no change to operating income.

*Rate Filings*

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. There were no rate cases completed within our natural gas distribution segment for the first three quarters of fiscal 2011.

*GRIP Filings*

The Gas Reliability Infrastructure Program (GRIP) in Texas allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. The following table summarizes our GRIP filings with effective dates during the nine months ended June 30, 2011.

| Division | Calendar Year | Incremental Net Utility Plant Investment | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | (In thousands) | (In thousands) | |
| *2011 GRIP:* | | | | |
| West Texas/Lubbock & WT Cities Environs | 2010 | $ 17,677 | $343 | 06/01/2011 |
| Mid-Tex/Environs | 2010 | 107,840 | 576 | 06/27/2011 |
| Total 2011 GRIP | | $125,517 | $919 | |

*Annual Rate Filing Mechanisms*

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the nine months ended June 30, 2011.

| Division | Jurisdiction | Test Year Ended | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2011 Filings:* | | | | |
| Mid-Tex | Settled Cities | 12/31/2009 | $23,122 | 10/01/2010 |
| Louisiana | TransLa | 09/30/2010 | 350 | 04/01/2011 |
| Mid-Tex | Dallas | 12/31/2010 | 1,598 | 07/01/2011 |
| Total 2011 Filings | | | $25,070 | |

*Other Ratemaking Activity*

The following table summarizes other ratemaking activity during the nine months ended June 30, 2011:

| Division | Jurisdiction | Rate Activity | Additional Annual Operating Income | Effective Date |
|---|---|---|---|---|
| | | | (In thousands) | |
| *2011 Other Rate Activity:* | | | | |
| Kentucky/Mid-States | Georgia | PRP Surcharge | $ 764 | 10/01/2010 |
| Colorado-Kansas | Colorado | AMI(1) | 349 | 12/01/2010 |
| Colorado-Kansas | Kansas | Ad Valorem(2) | 685 | 01/01/2011 |
| Kentucky/Mid-States | Missouri | ISRS(3) | 277 | 02/14/2011 |
| Total 2011 Other Rate Activity | | | $2,075 | |

(1) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of the Company's service area.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

***Regulated Transmission and Storage Segment***

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

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

***Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010***

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2011 and 2010 are presented below.

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 32,098 | $ 21,908 | $10,190 |
| Third-party transportation | 16,518 | 17,521 | (1,003) |
| Storage and park and lend services | 1,802 | 2,646 | (844) |
| Other | 3,152 | 2,882 | 270 |
| **Gross profit** | 53,570 | 44,957 | 8,613 |
| Operating expenses | 29,305 | 24,231 | 5,074 |
| **Operating income** | 24,265 | 20,726 | 3,539 |
| Miscellaneous income (expense) | (312) | 94 | (406) |
| Interest charges | 7,653 | 7,667 | (14) |
| **Income before income taxes** | 16,300 | 13,153 | 3,147 |
| Income tax expense | 5,748 | 4,688 | 1,060 |
| **Net income** | $ 10,552 | $ 8,465 | $ 2,087 |
| Gross pipeline transportation volumes — MMcf | 141,294 | 127,861 | 13,433 |
| Consolidated pipeline transportation volumes — MMcf | 112,564 | 100,770 | 11,794 |

On April 18, 2011, the Railroad Commission of Texas (RRC) issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $8.6 million increase in regulated transmission and storage gross profit was attributable primarily to a net $8.7 million increase as a result of this rate case.

Operating expenses increased $5.1 million primarily due to the following:

- $3.2 million due to higher levels of pipeline maintenance activities.
- $1.6 million due to higher depreciation expense.

At June 30, 2011, a GRIP filing was in progress with the RRC in which $12.6 million of additional annual operating income was requested. On July 26, 2011, the RRC approved the GRIP filing.

### *Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010*

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2011 and 2010 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| Mid-Tex transportation | $ 92,729 | $ 81,833 | $10,896 |
| Third-party transportation | 49,841 | 49,098 | 743 |
| Storage and park and lend services | 6,191 | 7,924 | (1,733) |
| Other | 8,792 | 8,143 | 649 |
| **Gross profit** | 157,553 | 146,998 | 10,555 |
| Operating expenses | 79,373 | 78,498 | 875 |
| **Operating income** | 78,180 | 68,500 | 9,680 |
| Miscellaneous income | 5,267 | 117 | 5,150 |
| Interest charges | 23,802 | 23,589 | 213 |
| **Income before income taxes** | 59,645 | 45,028 | 14,617 |
| Income tax expense | 21,252 | 16,039 | 5,213 |
| **Net income** | $ 38,393 | $ 28,989 | $ 9,404 |
| Gross pipeline transportation volumes — MMcf | 468,943 | 478,075 | (9,132) |
| Consolidated pipeline transportation volumes — MMcf | 305,898 | 295,126 | 10,772 |

The $10.6 million increase in regulated transmission and storage gross profit was attributable primarily due to the following:

- $8.7 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $6.2 million increase associated with our GRIP filings.

These increases were partially offset by the following:

- $2.8 million decrease due to a decline in throughput to our Mid-Tex Division.
- $2.4 million decrease due to decreased transportation fees.

Operating expenses increased $0.9 million primarily due to the following:

- $3.0 million increase due to higher depreciation expense.
- $1.8 million increase due to higher ad valorem taxes.

These increases were partially offset by a $1.3 million decrease related to lower levels of pipeline maintenance activities.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

***Nonregulated Segment***

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to offset the original financial instruments. If AEH elects to defer the withdrawal of gas, it will execute new financial instruments to correspond to the revised withdrawal schedule and allow the original financial instrument to settle as contracted.

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

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

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

***Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010***

Financial and operational highlights for our nonregulated segment for the three months ended June 30, 2011 and 2010 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

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

| | Three Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 11,631 | $ 12,550 | $ (919) |
| Storage and transportation services | 4,042 | 3,319 | 723 |
| Other | 1,177 | 1,345 | (168) |
| | 16,850 | 17,214 | (364) |
| Asset optimization[1] | (3,623) | 9,303 | (12,926) |
| **Total realized margins** | 13,227 | 26,517 | (13,290) |
| **Unrealized margins** | 178 | (14,746) | 14,924 |
| **Gross profit** | 13,405 | 11,771 | 1,634 |
| Operating expenses, excluding asset impairment | 9,359 | 10,667 | (1,308) |
| Asset impairment | 10,988 | — | 10,988 |
| **Operating income (loss)** | (6,942) | 1,104 | (8,046) |
| Miscellaneous income | 168 | 511 | (343) |
| Interest charges | 283 | 1,912 | (1,629) |
| **Loss before income taxes** | (7,057) | (297) | (6,760) |
| Income tax expense (benefit) | (3,160) | 420 | (3,580) |
| **Net loss** | $ (3,897) | $ (717) | $ (3,180) |
| Gross nonregulated delivered gas sales volumes — MMcf | 104,658 | 91,854 | 12,804 |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 88,382 | 75,014 | 13,368 |
| Net physical position (Bcf) | 16.7 | 20.1 | (3.4) |

[1] Net of storage fees of $3.8 million and $3.3 million.

Realized margins for gas delivery, storage and transportation services and other services were $16.9 million during the three months ended June 30, 2011 compared with $17.2 million for the prior-year quarter. The decrease primarily reflects a decrease of $0.03/Mcf for consolidated delivered gas margins in the current quarter, partially offset by an 18 percent increase in consolidated delivered gas volumes due to new customers in the power generation market.

The $12.9 million decrease in realized asset optimization margins from the prior-year quarter reflects the impact of continued weak natural gas market fundamentals, which have reduced price volatility and compressed spot to forward spread values resulting in less favorable trading opportunities. As a result, during the current quarter, AEH captured smaller spread values from its asset optimization activities. This contrasts to the prior-year quarter, when AEH recognized higher spread values that it had captured from rolling positions.

Weak market fundamentals have also reduced the demand and fees paid for storage. During the quarter, AEH started to capitalize on falling storage demand fees by replacing expiring storage contracts with new contracts with lower storage demand fees and allowing non-strategic contracts to expire without renewing them. This should improve AEH's ability to realize gains from its asset optimization activities in future periods.

The decrease in realized asset optimization margins was offset by a $14.9 million increase in unrealized margins that reflects the quarter-over-quarter timing of realized margins coupled with lower natural gas price volatility.

Operating expenses decreased $1.3 million primarily due to lower employee costs.

Asset impairment reflects the $11.0 million pre-tax impairment of certain natural gas gathering assets recorded in the current quarter.

Interest charges decreased $1.6 million primarily due to a decrease in intercompany borrowings.

***Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010***

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2011 and 2010 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | (In thousands, unless otherwise noted) | | |
| **Realized margins** | | | |
| Gas delivery and related services | $ 46,842 | $ 45,763 | $ 1,079 |
| Storage and transportation services | 10,913 | 9,746 | 1,167 |
| Other | 3,956 | 3,907 | 49 |
| | 61,711 | 59,416 | 2,295 |
| Asset optimization[1] | (344) | 46,694 | (47,038) |
| **Total realized margins** | 61,367 | 106,110 | (44,743) |
| **Unrealized margins** | (2,726) | (10,403) | 7,677 |
| **Gross profit** | 58,641 | 95,707 | (37,066) |
| Operating expenses, excluding asset impairment | 30,200 | 35,552 | (5,352) |
| Asset impairment | 30,270 | — | 30,270 |
| **Operating income (loss)** | (1,829) | 60,155 | (61,984) |
| Miscellaneous income | 764 | 1,524 | (760) |
| Interest charges | 1,759 | 8,035 | (6,276) |
| **Income (loss) before income taxes** | (2,824) | 53,644 | (56,468) |
| Income tax expense (benefit) | (1,364) | 21,608 | (22,972) |
| **Net income (loss)** | $ (1,460) | $ 32,036 | $(33,496) |
| Gross nonregulated delivered gas sales volumes — MMcf | 339,747 | 317,992 | 21,755 |
| Consolidated nonregulated delivered gas sales volumes — MMcf | 290,486 | 267,136 | 23,350 |
| Net physical position (Bcf) | 16.7 | 20.1 | (3.4) |

(1) Net of storage fees of $10.7 million and $10.0 million.

Realized margins for gas delivery, storage and transportation services and other services were $61.7 million during the nine months ended June 30, 2011 compared with $59.4 million for the prior-year period. The increase primarily reflects a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market and a $1.2 million increase in margins from storage and transportation services, attributable to new drilling projects in the Barnett Shale area.

The $47.0 million decrease in realized asset optimization margins from the prior-year period primarily reflects greater intramonth trading gains realized in the prior-year period from more favorable trading opportunities in the daily cash market, combined with lower realized gains in the current-year period due to continued weak natural gas market fundamentals.

Unrealized margins increased $7.7 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.4 million primarily due to lower employee expenses.

Asset impairment includes the aforementioned $11.0 million pre-tax impairment charge related to certain natural gas gathering assets. In addition, an asset impairment charge of $19.3 million was recorded in March 2011 related to our investment in Fort Necessity. As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. As such, we recorded a pretax noncash impairment to write off substantially all of our investment in the project during the second quarter of fiscal 2011.

Interest charges decreased $6.3 million primarily due to a decrease in intercompany borrowings.

*Asset Optimization Activities*

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at June 30, 2011 and 2010.

| | June 30 | |
|---|---|---|
| | 2011 | 2010 |
| | (In millions, unless otherwise noted) | |
| Economic value | $ (7.7) | $ (8.5) |
| Associated unrealized losses | 8.3 | 16.5 |
| Subtotal | 0.6 | 8.0 |
| Related fees(1) | (21.4) | (13.8) |
| Potential gross profit (loss) | $(20.8) | $ (5.8) |
| Net physical position (Bcf) | 16.7 | 20.1 |

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization activities. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of June 30, 2011 and 2010.

During the nine months ended June 30, 2011, our nonregulated segment's economic value decreased from ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to ($7.7) million, or ($0.46)/Mcf. This compares favorably to economic value at June 30, 2010 of ($8.5) million, or ($0.42)/Mcf.

For the nine months ended June 30, 2011, the decrease in our economic value was primarily the result of withdrawing physical gas below our overall weighted average cost of gas while settling financial instruments with higher average prices.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of June 30, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

**Liquidity and Capital Resources**

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we have been executing our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit, including the following.

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.

- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and certain regulatory restrictions; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

As a result of these changes, we now have $975 million of availability from our commercial paper program and three committed revolving credit facilities with third parties.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011 using funds drawn from commercial paper. We refinanced this debt on a long-term basis through the issuance of $400 million 5.50% 30-year unsecured senior notes on June 10, 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury lock and settlement. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2011.

**Cash Flows**

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the nine months ended June 30, 2011 and 2010 are presented below.

| | Nine Months Ended June 30 | | |
|---|---|---|---|
| | 2011 | 2010 | Change |
| | | (In thousands) | |
| Total cash provided by (used in) | | | |
| Operating activities | $ 519,562 | $ 594,564 | $(75,002) |
| Investing activities | (393,656) | (362,787) | (30,869) |
| Financing activities | (140,429) | (162,597) | 22,168 |
| Change in cash and cash equivalents | (14,523) | 69,180 | (83,703) |
| Cash and cash equivalents at beginning of period | 131,952 | 111,203 | 20,749 |
| Cash and cash equivalents at end of period | $ 117,429 | $ 180,383 | $(62,954) |

*Cash flows from operating activities*

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and working capital changes, particularly within our natural gas distribution segment resulting from 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, 2011, we generated operating cash flow of $519.6 million from operating activities compared with $594.6 million for the nine months ended June 30, 2010. The $75.0 million decrease in operating cash flows primarily reflects the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

*Cash flows from investing activities*

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

Capital expenditures for fiscal 2011 are expected to range from $610 million to $625 million. For the nine months ended June 30, 2011, capital expenditures were $390.3 million compared with $362.3 million for the nine months ended June 30, 2010. The $28.0 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the development of a new customer service system in the current year, partially offset by the costs incurred in the prior fiscal year to relocate the company's information technology data center.

*Cash flows from financing activities*

For the nine months ended June 30, 2011, our financing activities used $140.4 million of cash compared with $162.6 million of cash used in the prior-year period, primarily due to higher proceeds from debt issuances in the current year, including the following:

- $394.6 million net cash proceeds received in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- $20.1 million cash received in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- $27.8 million cash received in March 2011 related to the unwinding of two Treasury locks.

These higher proceeds were partially offset by higher repayment activity, including the following:

- $360.1 million for scheduled long-term debt repayments. In the current-year period, $360.1 million of long-term debt was repaid, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011. In the prior-year period, $0.1 million of long-term debt was repaid.
- $56.1 million for short-term debt repayments. In the current-year period, $132.1 million of short-term debt was repaid, compared with $76.0 million in the prior-year period.
- $4.1 million for the repurchase of equity awards. In the current-year period, we repurchased $5.3 million equity awards, compared with $1.2 million in the prior-year period.

The following table summarizes our share issuances for the nine months ended June 30, 2011 and 2010.

| | Nine Months Ended June 30 | |
|---|---|---|
| | 2011 | 2010 |
| Shares issued: | | |
| Direct Stock Purchase Plan | — | 103,529 |
| Retirement Savings Plan and Trust | — | 79,722 |
| 1998 Long-Term Incentive Plan | 663,555 | 375,039 |
| Outside Directors Stock-for-Fee Plan | 1,801 | 2,689 |
| Total shares issued | 665,356 | 560,979 |

The year-over-year change in the number of shares issued primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During the nine months ended June 30, 2011, we cancelled and retired 169,269 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our accelerated share repurchase agreement, which are not included in the table above.

**Share Repurchase Agreement**

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

**Credit Facilities**

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

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and three committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of June 30, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $900.2 million. These facilities are described in further detail in Note 6 to the unaudited condensed consolidated financial statements.

**Shelf Registration**

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At June 30, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

### Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). On May 11, 2011, Moody's upgraded our senior unsecured debt rating to Baa1 from Baa2, with a ratings outlook of stable, citing steady rate increases, improving credit metrics and a strategic focus on lower risk regulated activities as reasons for the upgrade. On June 2, 2011, Fitch upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing a constructive regulatory environment, strategic focus on lower risk regulated activities and the geographic diversity of our regulated operations as key rating factors. As of June 30, 2011, S&P maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

| | S&P | Moody's | Fitch |
|---|---|---|---|
| Unsecured senior long-term debt | BBB+ | Baa1 | A- |
| Commercial paper | A-2 | P-2 | F-2 |

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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

### Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2011. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

### Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2011, September 30, 2010 and June 30, 2010:

| | June 30, 2011 | | September 30, 2010 | | June 30, 2010 | |
|---|---|---|---|---|---|---|
| | (In thousands, except percentages) | | | | | |
| Short-term debt | $ — | — | $ 126,100 | 2.8% | $ — | — |
| Long-term debt | 2,208,540 | 48.6% | 2,169,682 | 48.5% | 2,169,677 | 48.4% |
| Shareholders' equity | 2,335,824 | 51.4% | 2,178,348 | 48.7% | 2,313,730 | 51.6% |
| Total | $4,544,364 | 100.0% | $4,474,130 | 100.0% | $4,483,407 | 100.0% |

Total debt as a percentage of total capitalization, including short-term debt, was 48.6 percent at June 30, 2011, 51.3 percent at September 30, 2010 and 48.4 percent at June 30, 2010. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

### Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2011.

### Risk Management Activities

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

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and nine months ended June 30, 2011 and 2010:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $ 30,533 | $(21,735) | $(49,600) | $(14,166) |
| Contracts realized/settled | (13) | (20) | (51,058) | (34,438) |
| Fair value of new contracts | 1,801 | 182 | 2,872 | (2,054) |
| Other changes in value | (34,845) | 1,183 | 95,262 | 30,268 |
| Fair value of contracts at end of period | $ (2,524) | $(20,390) | $ (2,524) | $(20,390) |

The fair value of our natural gas distribution segment's financial instruments at June 30, 2011 is presented below by time period and fair value source:

| | Fair Value of Contracts at June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(3,235) | $711 | $— | $— | $(2,524) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(3,235) | $711 | $— | $— | $(2,524) |

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2011 and 2010:

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| | (In thousands) | | | |
| Fair value of contracts at beginning of period | $(12,942) | $14,227 | $(12,374) | $ 26,698 |
| Contracts realized/settled | 3,357 | (8,100) | 3,282 | (32,342) |
| Fair value of new contracts | — | — | — | — |
| Other changes in value | (1,824) | (8,337) | (2,317) | 3,434 |
| Fair value of contracts at end of period | (11,409) | (2,210) | (11,409) | (2,210) |
| Netting of cash collateral | 15,382 | 18,017 | 15,382 | 18,017 |
| Cash collateral and fair value of contracts at period end | $ 3,973 | $15,807 | $ 3,973 | $ 15,807 |

The fair value of our nonregulated segment's financial instruments at June 30, 2011 is presented below by time period and fair value source:

| | Fair Value of Contracts at June 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(5,336) | $(6,097) | $24 | $— | $(11,409) |
| Prices based on models and other valuation methods | — | — | — | — | — |
| Total Fair Value | $(5,336) | $(6,097) | $24 | $— | $(11,409) |

**Pension and Postretirement Benefits Obligations**

For the nine months ended June 30, 2011 and 2010, our total net periodic pension and other benefits costs were $42.7 million and $38.1 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Accordingly, our fiscal 2011 pension and postretirement medical costs for the nine months ended June 30, 2011 were significantly higher than the prior-year period.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. An immaterial curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $12 million to these plans during fiscal 2011.

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

## OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and nine month periods ended June 30, 2011 and 2010.

*Natural Gas Distribution Sales and Statistical Data — Continuing Operations*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| **METERS IN SERVICE, end of period** | | | | |
| Residential | 2,845,554 | 2,841,716 | 2,845,554 | 2,841,716 |
| Commercial | 258,448 | 262,349 | 258,448 | 262,349 |
| Industrial | 2,319 | 2,359 | 2,319 | 2,359 |
| Public authority and other | 10,206 | 10,117 | 10,206 | 10,117 |
| Total meters | 3,116,527 | 3,116,541 | 3,116,527 | 3,116,541 |
| **INVENTORY STORAGE BALANCE — Bcf** | 36.3 | 32.8 | 36.3 | 32.8 |
| **SALES VOLUMES — MMcf[1]** | | | | |
| Gas sales volumes | | | | |
| Residential | 17,077 | 17,060 | 150,154 | 173,787 |
| Commercial | 14,149 | 13,690 | 79,632 | 88,260 |
| Industrial | 3,922 | 3,490 | 15,115 | 15,236 |
| Public authority and other | 1,863 | 1,373 | 8,764 | 8,713 |
| Total gas sales volumes | 37,011 | 35,613 | 253,665 | 285,996 |
| Transportation volumes | 31,036 | 28,678 | 102,824 | 101,449 |
| Total throughput | 68,047 | 64,291 | 356,489 | 387,445 |
| **OPERATING REVENUES (000's)[1]** | | | | |
| Gas sales revenues | | | | |
| Residential | $ 232,725 | $ 230,333 | $1,379,223 | $1,602,510 |
| Commercial | 118,916 | 116,933 | 593,860 | 685,996 |
| Industrial | 22,525 | 19,108 | 85,641 | 90,468 |
| Public authority and other | 12,013 | 9,125 | 58,096 | 61,595 |
| Total gas sales revenues | 386,179 | 375,499 | 2,116,820 | 2,440,569 |
| Transportation revenues | 13,946 | 13,303 | 47,364 | 46,276 |
| Other gas revenues | 6,906 | 7,517 | 23,723 | 25,187 |
| Total operating revenues | $ 407,031 | $ 396,319 | $2,187,907 | $2,512,032 |
| Average transportation revenue per Mcf | $ 0.45 | $ 0.46 | $ 0.46 | $ 0.46 |
| Average cost of gas per Mcf sold | $ 5.59 | $ 5.76 | $ 5.19 | $ 5.80 |

See footnote following these tables.

*Natural Gas Distribution Sales and Statistical Data — Discontinued Operations*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Meters in service, end of period | 83,109 | 83,094 | 83,109 | 83,094 |
| Inventory storage balance — Bcf | 2.0 | 1.9 | 2.0 | 1.9 |
| Sales volumes — MMcf | | | | |
| Total gas sales volumes | 936 | 726 | 7,910 | 8,187 |
| Transportation volumes | 1,192 | 1,633 | 4,813 | 5,648 |
| Total throughput | 2,128 | 2,359 | 12,723 | 13,835 |
| Operating revenues (000's) | $11,524 | $ 8,952 | $71,047 | $62,121 |

*Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data*

| | Three Months Ended June 30 | | Nine Months Ended June 30 | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| **CUSTOMERS, end of period** | | | | |
| Industrial | 764 | 732 | 764 | 732 |
| Municipal | 61 | 61 | 61 | 61 |
| Other | 511 | 507 | 511 | 507 |
| Total | 1,336 | 1,300 | 1,336 | 1,300 |
| **NONREGULATED INVENTORY STORAGE BALANCE — Bcf** | 21.4 | 21.9 | 21.4 | 21.9 |
| **REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf**(1) | 141,294 | 127,861 | 468,943 | 478,075 |
| **NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(1)** | 104,658 | 91,854 | 339,747 | 317,992 |
| **OPERATING REVENUES (000's)**(1) | | | | |
| Regulated transmission and storage | $ 53,570 | $ 44,957 | $ 157,553 | $ 146,998 |
| Nonregulated | 491,285 | 427,405 | 1,550,456 | 1,652,453 |
| Total operating revenues | $544,855 | $472,362 | $1,708,009 | $1,799,451 |

Note to preceding tables:

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

## RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the nine months ended June 30, 2011, there were no material changes in our quantitative and qualitative disclosures about market risk.

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

**Management's Evaluation of Disclosure Controls and Procedures**

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

**Changes in Internal Control over Financial Reporting**

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## PART II. OTHER INFORMATION

**Item 1.** ***Legal Proceedings***

During the nine months ended June 30, 2011, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

**Item 6.** ***Exhibits***

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

## SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

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

Date: August 4, 2011

## EXHIBITS INDEX
### Item 6

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 12 | Computation of ratio of earnings to fixed charges | |
| 15 | Letter regarding unaudited interim financial information | |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications* | |
| 101.INS | XBRL Instance Document** | |
| 101.SCH | XBRL Taxonomy Extension Schema** | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase** | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase** | |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase** | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase** | |

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.