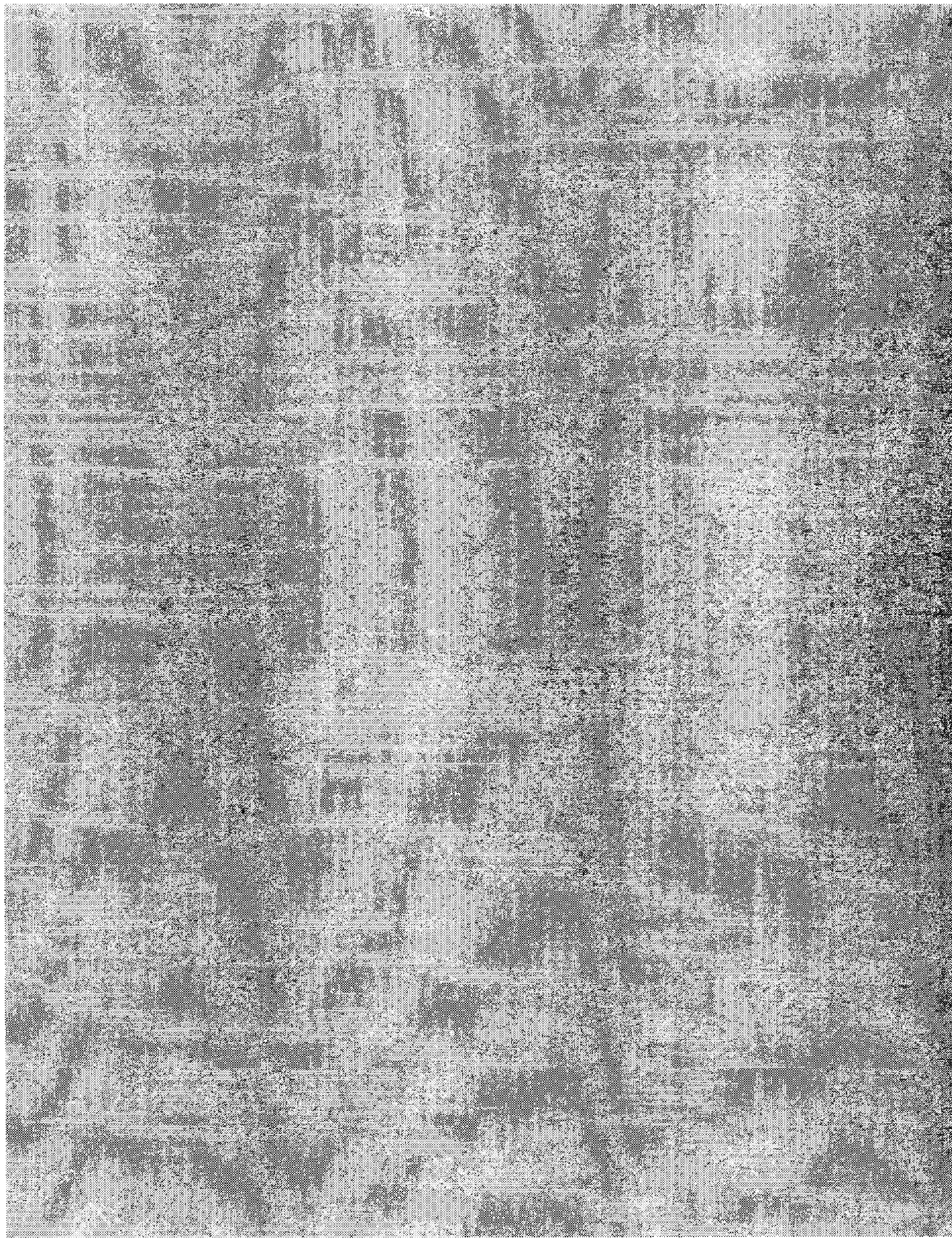

ATMOS ENERGY CORPORATION

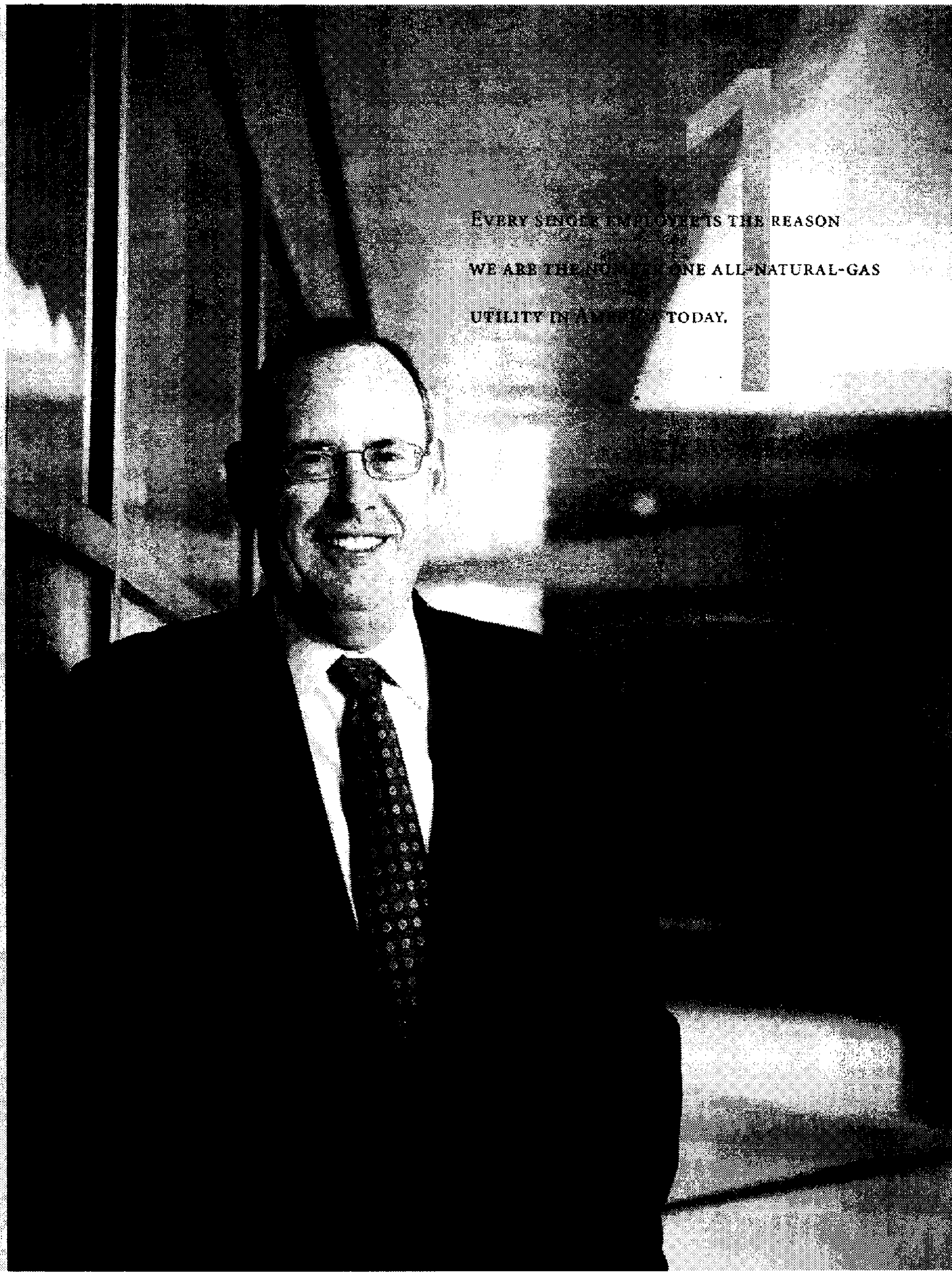
CELEBRATING
# 100 YEARS of SERVICE

2006 SUMMARY ANNUAL REPORT



years ago,
a few visionary pioneers founded Amarillo Gas Company to bring energy to the frontier.

Today, some 4,600 Atmos Energy employees keep that energy alive for 3.2 million customers across the nation.



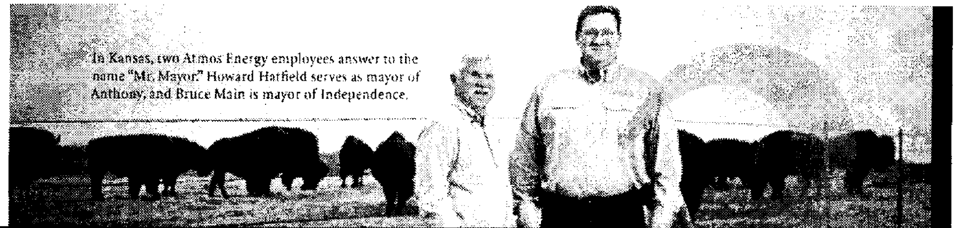
**EVERY SINGLE EMPLOYEE IS THE REASON WE ARE THE NUMBER ONE ALL-NATURAL-GAS UTILITY IN AMERICA TODAY.**

In 2006, we celebrated a century of bringing the energy of America to homes and businesses across our vast countryside. In this annual report, I'm proud to share with you the literally hundreds of great things about our 100-year-old company. Our spirit has remained strong through the decades. From the early days of finding and delivering natural gas, to innovation in our homes and places of business, to the unwavering commitment in the wake of disasters like Hurricane Katrina, the spirit of our employees remains stronger than ever as we look forward to our next 100 years.

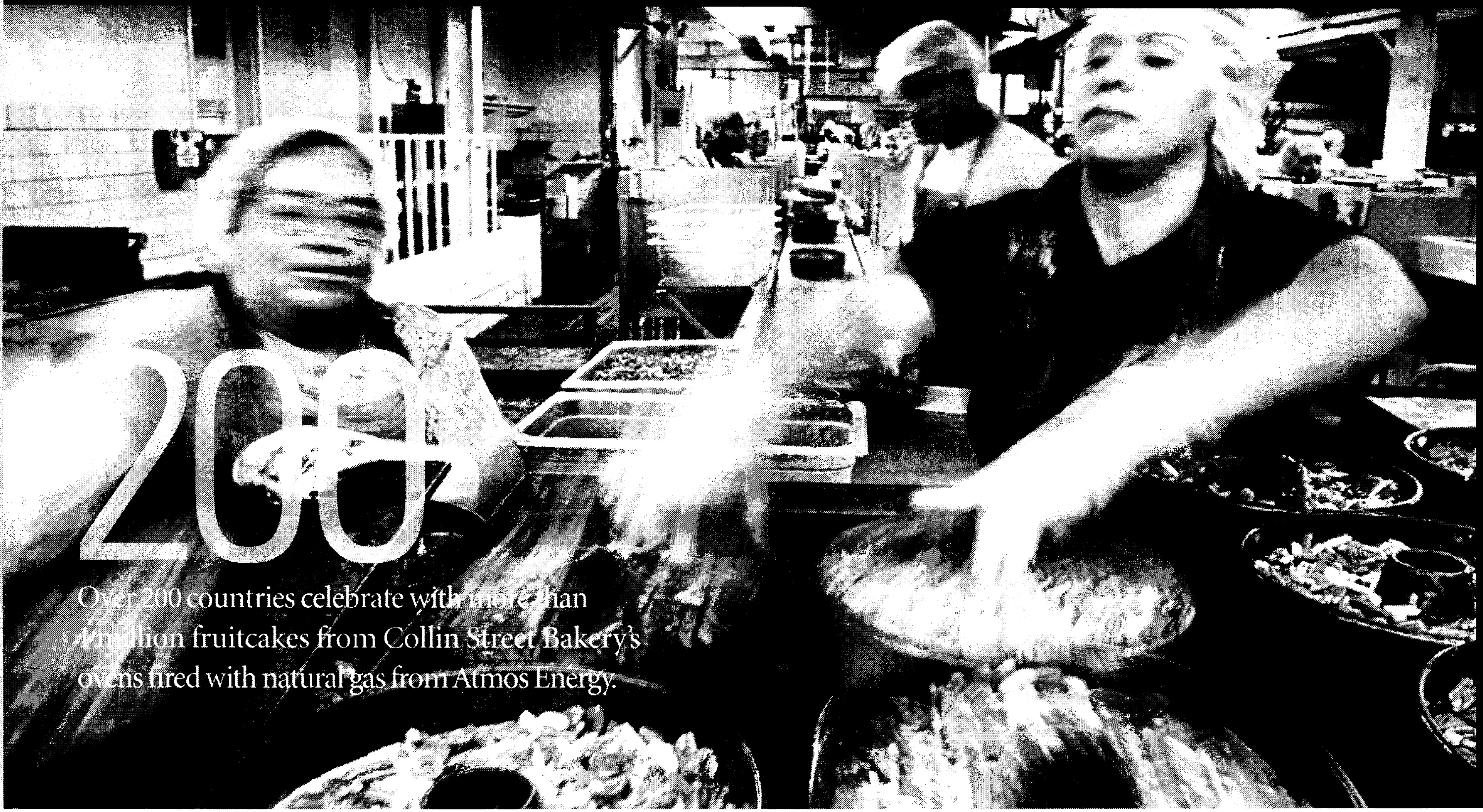
— Robert W. Best
[illegible]

[illegible]

100 The oil and gas boom brought new prosperity to Amarillo—and hundreds of road rally racers.

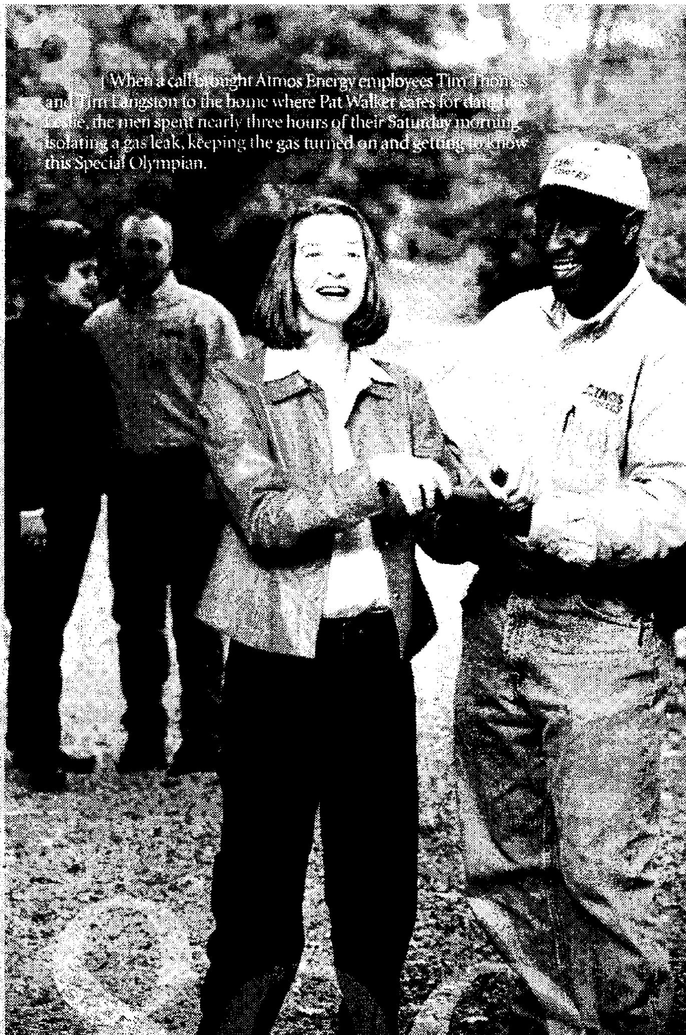


In Kansas, two Atmos Energy employees answer to the name "Mr. Mayor." Howard Hatfield serves as mayor of Anthony, and Bruce Main is mayor of Independence.



200

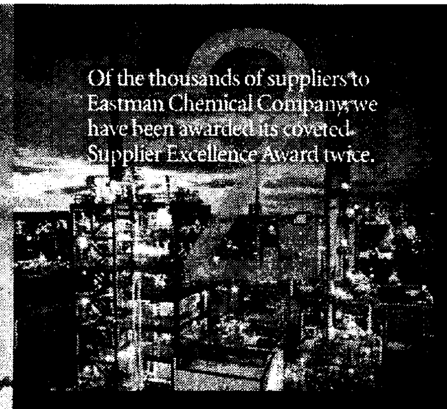
Over 200 countries celebrate with more than 4 million fruitcakes from Collin Street Bakery's ovens fired with natural gas from Atmos Energy.



When a call brought Atmos Energy employees Tim Thomas and Tim Langston to the home where Pat Walker cares for daughter Leslie, the men spent nearly three hours of their Saturday morning isolating a gas leak, keeping the gas turned on and getting to know this Special Olympian.

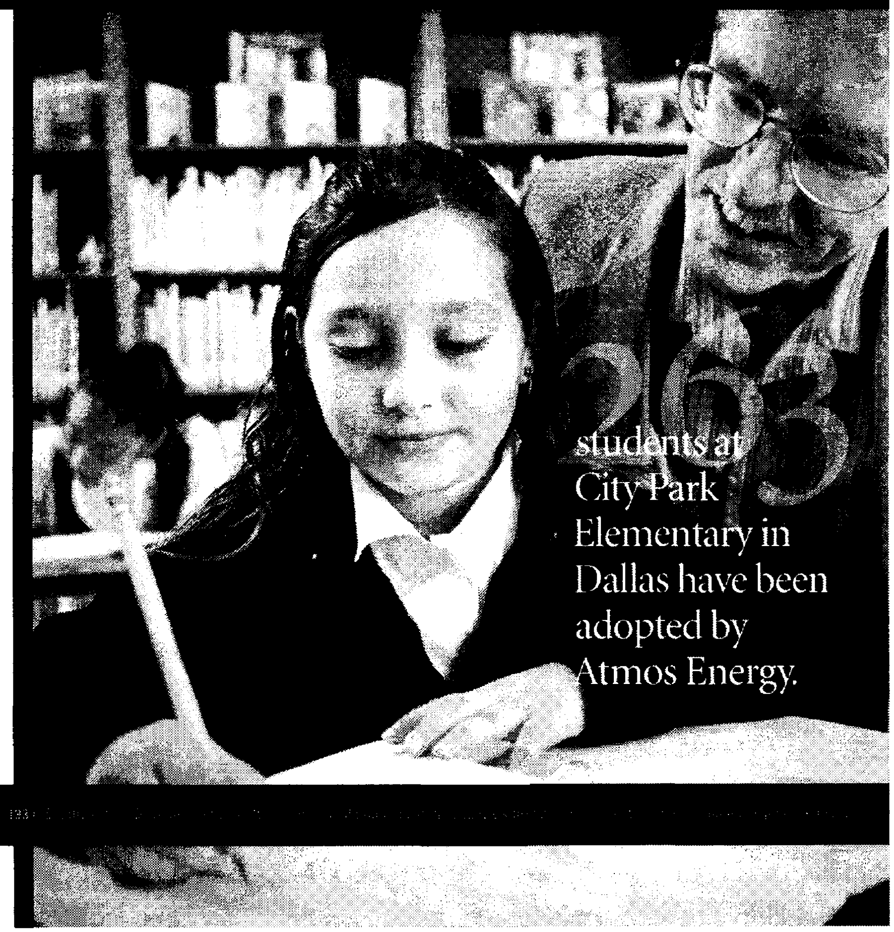
95

Atmos Energy leads the industry in equipping its meter readers with the Bite Terminator, a new device that reduces dog bites by 95 percent without harming Fido.



Of the thousands of suppliers to Eastman Chemical Company, we have been awarded its coveted Supplier Excellence Award twice.

60 Natural gas has long been vital to business. Today, 60 percent of all natural gas is used by industry and to generate electricity.

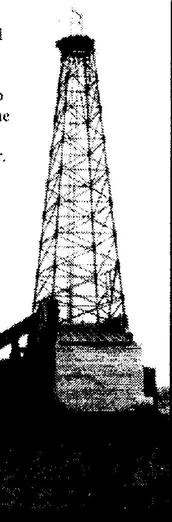


263 students at City Park Elementary in Dallas have been adopted by Atmos Energy.

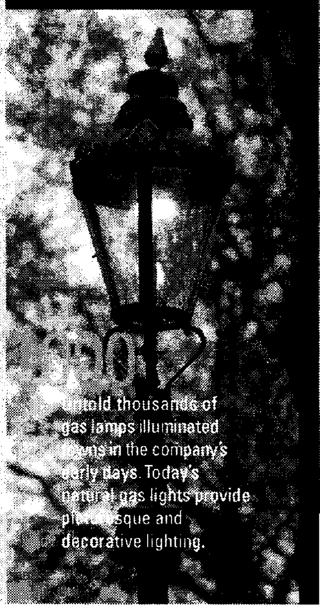
850

53

100



1 | One hole in the ground that changed the world. In 1918, Amarillo Gas struck one of the largest gas fields ever.



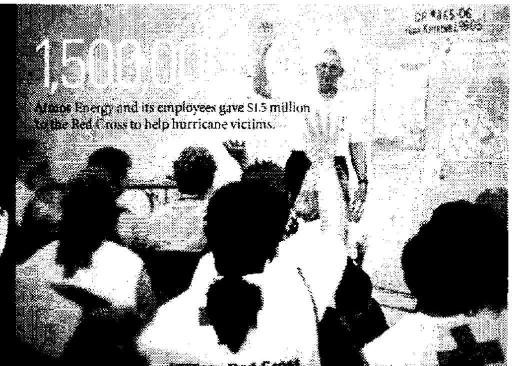
Untold thousands of gas lamps illuminated towns in the company's early days. Today's natural gas lights provide picturesque and decorative lighting.


The 23 Segways Atmos Energy has in operation so far have improved meter readers' efficiency by ... percent and have reduced injuries. That's what we call making great strides.


280

After Hurricane Katrina, 280 Atmos Energy employees from outside Louisiana relocated to the storm-ravaged area. Living in company-provided trailers, they restored 1.5 million feet of gas main in nine months.

Taking health and safety to heart, we have installed 186 defibrillators in our offices.



1,500,000

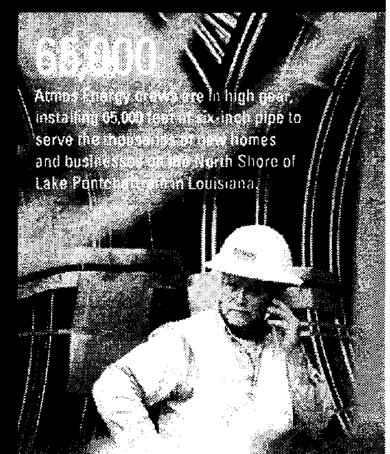
Atmos Energy and its employees gave $1.5 million to the Red Cross to help hurricane victims.

500 | Five hundred gas meters were under water in Iberia, St. Mary and Vermilion Parishes as a result of Hurricane Katrina.

Online gas customers have grown by [illegible] percent this year. Almost half a million of our utility customers now have online accounts.

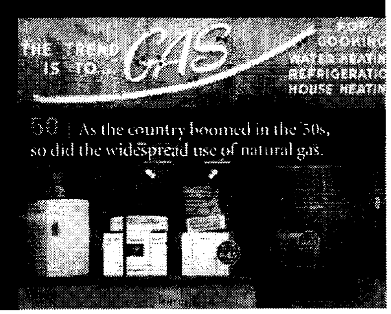
40

Kent Maycut, a service technician from St. Bernard Parish, spent several days in a small boat rescuing 40 victims of the post-Katrina flood.

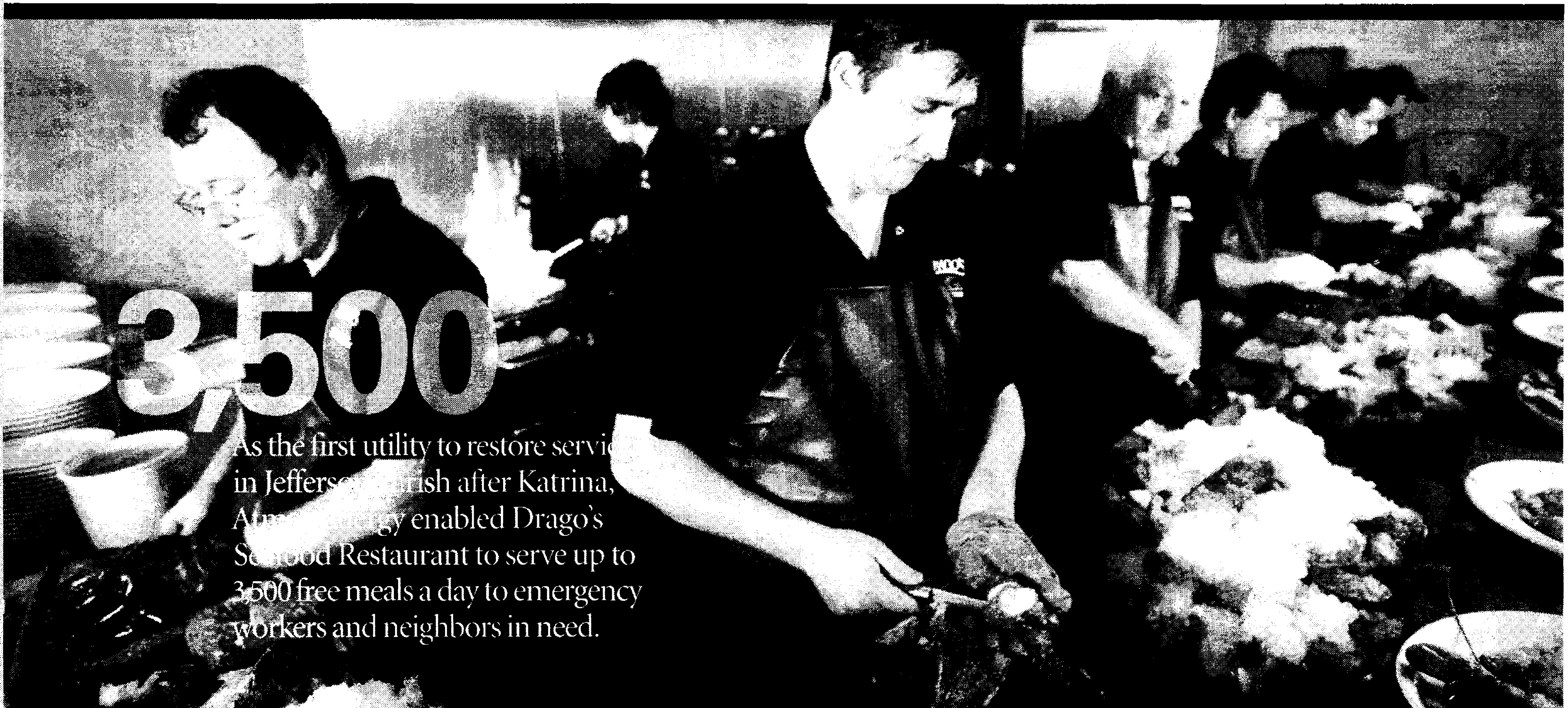


66,000

Atmos Energy crews are in high gear, installing 66,000 feet of six-inch pipe to serve the thousands of new homes and businesses on the North Shore of Lake Pontchartrain in Louisiana.

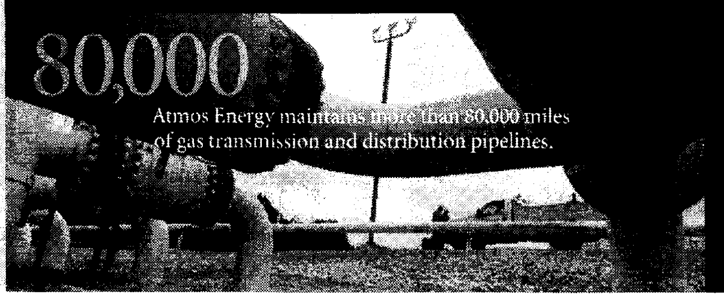



50 | As the country boomed in the '50s, so did the widespread use of natural gas.



# 3,500

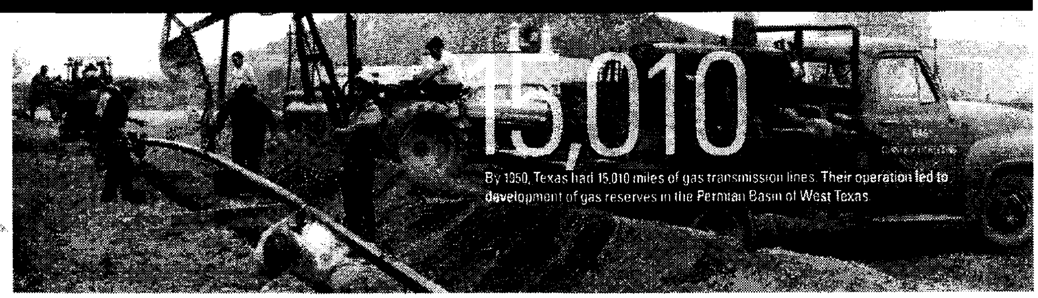
As the first utility to restore service in Jefferson Parish after Katrina, Atmos Energy enabled Drago's Seafood Restaurant to serve up to 3,500 free meals a day to emergency workers and neighbors in need.



# 80,000

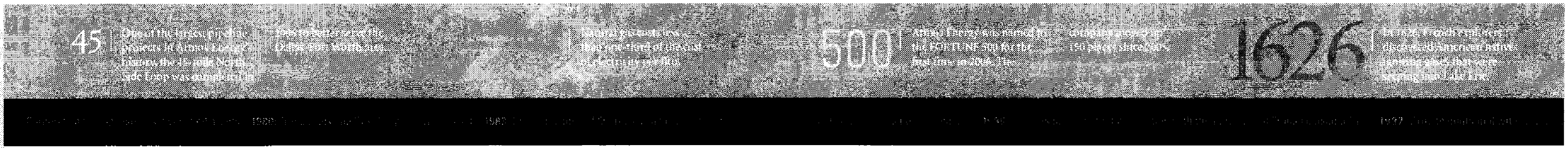
Atmos Energy maintains more than 80,000 miles of gas transmission and distribution pipelines.

**1,950** | Our employees have walked 1,950 kilometers for the Susan G. Komen Breast Cancer Foundation Race for the Cure.®



# 15,010

By 1950, Texas had 15,010 miles of gas transmission lines. Their operation led to development of gas reserves in the Permian Basin of West Texas.






# Dear Fellow Shareholder:

We have many reasons to celebrate 2006, not the least of which was our company's 100th birthday.

In our centennial year, Atmos Energy delivered exceptional financial results that were driven by increased sales volumes and higher margins in our nonutility segment. At the same time, our utility operations implemented improved rate designs to strengthen our future financial performance.

Net income for the fiscal year increased 9 percent to $147.7 million from $135.8 million in fiscal 2005, and earnings per diluted share grew by 10 cents to $1.82.

We paid dividends of $1.26 per share, resulting in a yield of between 4 percent and 5 percent. In November 2006, the board of directors declared our 19th consecutive annual dividend increase, raising the dividend by 2 cents a share. The indicated rate for fiscal 2007 is $1.28.

During 2006, we achieved smooth management transitions in both our utility and nonutility operations. Kim R. Cocklin assumed responsibilities as senior vice president, utility operations, and Mark H. Johnson was named senior vice president, nonutility operations.

We also began recovering from Hurricanes Katrina and Rita, which initially had affected service to more than 60 percent of our Louisiana customers.

Although Atmos Energy has changed in many ways during the past century, it has remained true to the founders' core vision to serve the public as a natural gas company.

Today, that vision translates into our complementary strategy of natural gas utility services and nonutility gas marketing, pipeline and storage services—a strategy that produced exceptional results in fiscal 2006.

### NONUTILITY EARNINGS INCREASE 73 PERCENT

A very bright spot in 2006 was our nonutility operations. Earnings from these operations offset a 35 percent decline in our utility earnings to contribute a record-setting $94.7 million to net income, or $1.17 per diluted share.

Our gas marketing subsidiary, Atmos Energy Marketing (AEM), was able to realize $68.7 million more in margins primarily as a result of the extreme volatility in natural gas commodity prices last winter. AEM used its experience and expertise as one of the country's leading gas marketers to help many public utilities, municipalities and industrial customers contend with the wide swings in wholesale gas prices. As a result, AEM increased its 2006 marketing sales volumes by 46 billion cubic feet (Bcf) to 284.0 Bcf.

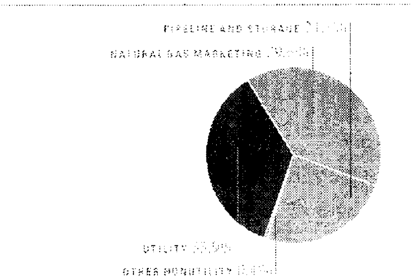
Furthermore, our pipeline and storage segment, also part of our nonutility operations, achieved higher transportation and related-service margins and favorable arbitrage spreads on its storage contracts. The segment contributed $35.6 million to net income, a 16 percent increase over its contribution in fiscal 2005. Consolidated pipeline and storage throughput increased to 420.2 Bcf from 383.4 Bcf in fiscal 2005.

A significant step we took during 2006—one that promises favorable returns and future opportunities—was our expansion into natural gas gathering. We expect to be able to use many of the same operating and marketing strengths found in our pipeline business in the gathering business. A gathering system collects raw gas from producers' wells and transports it to a processing and sales terminal. From there, larger regulated pipelines carry the gas to market.

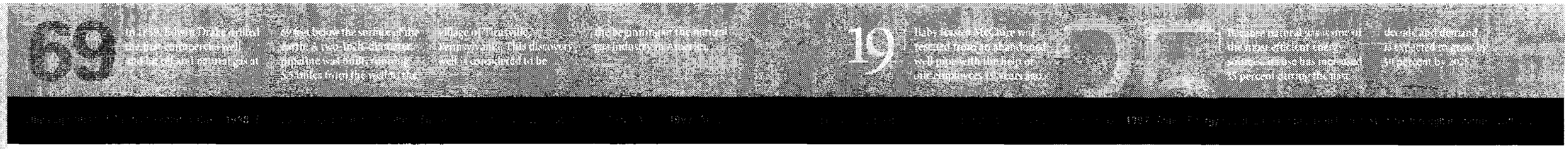
In October 2006, we received an order from the Federal Energy Regulatory Commission (FERC) exempting our proposed Straight Creek Gathering System from FERC regulation. This gathering system will use a 20-inch backbone pipeline running approximately 60 miles through the Big Sandy natural gas producing region in eastern Kentucky. It will be able to transport up to 100,000 million Btu (MMBtu) a day of gas when it goes into operation in 2007, with the capability to expand throughput up to 225,000 MMBtu a day.

The Big Sandy producing region historically has not had sufficient gathering capacity to handle the available supply. It's estimated that our project could generate more than $150 million a year in

FISCAL 2006 NET INCOME BY SEGMENT




Contributions from utility and nonutility operations




wellhead sales revenues, severance taxes, property taxes and royalty-owner revenues. Atmos Energy and our minority partner, Kinzer Drilling Company, plan to invest between $75 million and $80 million in the project.

NEW RATE DESIGN SHOULD HELP UTILITY SEGMENT

Extremely volatile natural gas prices, one of the warmest winters on record and two of the worst hurricanes in American history strained our utility business by adding operating costs and lowering utility revenues.

to write off our irrigation properties in West Texas. The volumes of natural gas we deliver for irrigation pumping in Texas have continued to decline year after year and were not expected to generate enough cash flow from operations to recover our net investment.

On the positive side, our biggest financial success came in breakthroughs in rate design in our utility segment. These changes should help return our utility to strong performance in fiscal 2007 and beyond.

We secured protection from weather in our two largest divisions. In Texas, the





## We cannot control the weather and we cannot control the cost of natural gas; however, we can control how we address adverse situations.

In particular, unseasonably warm winter weather, which was 13 percent warmer than normal, reduced our utility earnings. Net income from utility operations fell to $53.0 million from $81.1 million in fiscal 2005. In addition, we lost approximately 230,000 utility customers in Louisiana until service could be restored after Hurricanes Katrina and Rita. About 26,500 of these customers became permanent losses with no plans for rebuilding homes or businesses.

Utility earnings also were reduced by a nonrecurring after-tax charge of $14.6 million, or 18 cents per diluted share,

Railroad Commission granted our Mid-Tex Division a weather normalization adjustment as part of a pending rate case. In Louisiana, the Public Service Commission allowed new rate provisions that protect our margins from warm winter weather, declining customer use and greater conservation.

As a result of these changes, more than 90 percent of our customer margins are now substantially insulated from the effects of adverse weather. This has been a primary goal to help safeguard our earnings.

We cannot control the weather and we cannot control the cost of natural gas; however, we can control how we address adverse situations. We believe that implementing sound rate-design principles benefits both the company and our customers over the long term.

KEEPING RATES CURRENT

We filed a number of rate cases during 2006, seeking rate increases and weather normalization adjustments as well as provisions to compensate for declining customer use and to recoup our costs for the natural gas consumed by customers with uncollectible accounts.

In Louisiana, the Public Service Commission acted quickly to allow a rate increase, subject to refund, of $10.8 million. The increase covered customer losses in Katrina-affected parishes and increases in rate base and operating expenses.

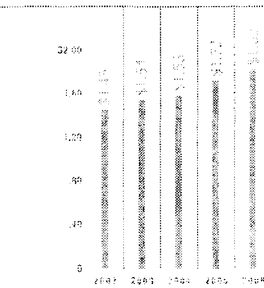
Our most significant rate filing was for a $60 million increase in Texas by our Mid-Tex Division to recover increases in the division's operating costs and its allowed rate of return. A decision is due no later than April 2007.

In Texas, we also continued to refresh our rates under the state's Gas Reliability Infrastructure Program, or GRIP. The program authorizes utilities to earn a rate of return on their incremental annual capital investments. It also reduces the regulatory lag time between when we make an investment and when we begin earning a return on it.

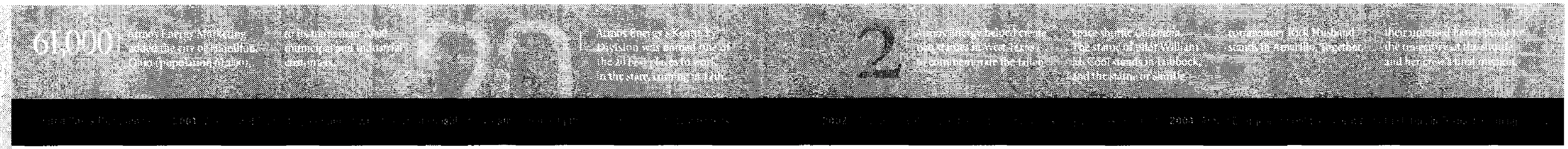
Since 2003, we have been able to increase base rates in Texas under GRIP by about $190 million while earning about $36 million in allowed return on that investment.

In Missouri, we reached a tentative settlement in a rate case seeking an

EARNINGS REVIEW




Net income per diluted share

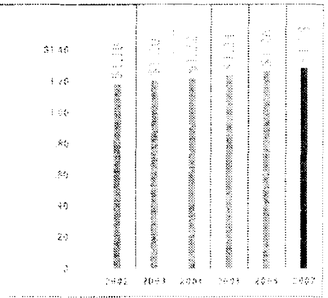





increase of $3.4 million. Significantly, the commission staff has agreed to support a fixed monthly delivery charge, which would allow us to earn our residential margins regardless of customers' usage. A final decision in the case is expected in March 2007.

In a contested case, the Tennessee Regulatory Authority ordered a $6.1 million reduction in our base rates, effective December 1, 2006. Because the company had absorbed a decade of inflation and expenses for system improvements without seeking a rate increase, we believe the current rates are deficient. We are continuing to analyze our rate strategy in Tennessee.

CASH DIVIDENDS PER SHARE



2007 dividend is the indicated rate

SUCCESS AND INDEPENDENCE

Strategic innovation has always set our company apart. For example, in 1986, the company was still a regional utility in West Texas with a complementary irrigation business. That year, CEO Charles Vaughan made a tender offer to acquire Trans Louisiana Gas Company. It was a bold step that set the course for the company's future growth.

"We had to do something because our service area was not growing," Vaughan said. "We had to buy something—or be bought ourselves."

Vaughan chose to diversify the company's operations into other states but to maintain its basic strategy as a regulated local distribution company.

Other successful acquisitions followed that confirmed the corporate vision and the long-standing belief in independence by our board of directors. Charles Vaughan set the dual hallmarks of financial success and corporate independence by which we operate today.

Atmos Energy has continued to expand, largely through mergers and acquisitions, to become the largest all-natural-gas distribution company in the country. Our 10 major acquisitions to date not only have bolstered our core utility business, but also have provided valuable diversification.

In particular, our acquisition in 2001 of the balance of Woodward Marketing has proved to be one of our best steps. We acquired one of the country's leading and most respected mid-tier natural gas marketing companies. Under JD Woodward's leadership, we greatly expanded the scope and scale of our nonutility business.

In 2004, we acquired the operations of TXU Gas Company. Not only did we obtain one of the most dynamic markets for natural gas distribution—Dallas-Fort Worth is now the nation's fourth largest metropolitan statistical area, but we also acquired a highly valuable intrastate gas pipeline system. Today, it is yielding superior returns in our pipeline and storage segment while offering growth due to the extensive rate of gas drilling in Texas and the producers' needs to transport the gas to markets.

STRATEGIC FOCUS

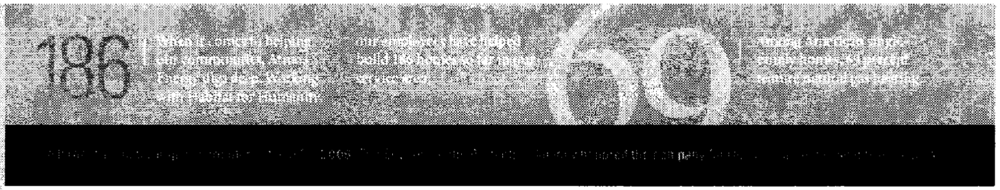
As Atmos Energy enters its second century, our strategic focus remains fixed on being financially successful by profitably delivering natural gas to our customers. We expect our earnings in fiscal 2007 to grow at our stated goal of 4 percent to 6 percent a year, on average. Our utility operations will remain our core business. And we will remain active in using acquisitions as an engine of future growth. However, we expect to be even more selective to find the right fit of properties.

We will invest most of our future growth capital in states with timely and adequate rates of return as well as in new nonutility projects. We expect our capital expenditures in fiscal 2007 will be between $425 million and $440 million, as compared to $425.3 million in fiscal 2006.

## I am confident that we are in a better position today than at any time in our past.

We will continue to work for federal laws to increase our country's natural gas supply in order to moderate gas prices. Towards this end, our interests are aligned perfectly with our customers' interests. We both want reasonable gas costs and lower volatility in gas prices.

Today, Atmos Energy is in an excellent position to expand its core business, stabilize its earnings and take advantage of its complementary strategy. We are pursuing consistent and focused strategies




to benefit our shareholders, customers and employees. Furthermore, natural gas remains the most valued energy source in American homes and businesses, offering comfort, convenience and efficiency. For all these reasons, I am confident that we are in a better position today than at any time in our past.

IN OBSERVANCE OF OUR CENTENNIAL

We have many reasons to celebrate Atmos Energy's 100th anniversary. But the one that's most important to me is our company's culture of developing exceptional employees.

They produced innovative solutions and found market opportunities that yielded our strong results in 2006 while they maintained the high level of service that we take pride in. Our employees took care of their customers and their fellow employees in a time of suffering and need.

Only hours after Hurricane Katrina devastated southern Louisiana and parts of Mississippi, our employees—more than 50 of whom lost their own homes—were in the field to ensure safety, to begin restoration where possible and to help their neighbors. For weeks thereafter, more than 450 of our employees from across our system worked up to 18-hour days under dangerous and difficult conditions. It is a fitting tribute to all our employees that the natural gas that powered the pumps to drain the toxic waters from New Orleans and to begin the healing came from Atmos Energy.

Local teams of employees from every operation joined together to "adopt" the families of our employees who lost their homes, autos and belongings. They held fundraisers, donated clothing, furniture, toys and supplies and went to the destroyed communities to help them rebuild their lives. Above all, they gave personal encouragement and strength to sustain their fellow employees through a difficult time.

Our first commitment always is to serve—safely, reliably and efficiently. This commitment ensures the value and integrity of your investment. It provides the confidence on which our enterprise has been built during the past 100 years. Even as our business and our employees change, service remains our defining mission.

Robert W. Best

Robert W. Best
*Chairman, President and Chief Executive Officer*
*November 22, 2006*



## MANAGEMENT TRIBUTES

**Gene C. Koonce**—Atmos Energy Corporation has benefited for nearly a decade from the wisdom and insights of Gene C. Koonce. Gene joined our board of directors in 1997 after our merger with United Cities Gas Company, where he had served as chairman, president and chief executive officer for 20 years. A long-time industry leader, Gene was also a distinguished community servant in the Greater Nashville area and across Tennessee. In February 2007, Gene will retire from the board, and we wish him and his wife, Bettye, our very best.

Two members of Atmos Energy Corporation's senior Management Committee retired during 2006. JD Woodward, who led our nonutility business, retired on April 1, and R. Earl Fischer, who led our utility operations, retired on September 30.

**JD Woodward**—began working with Atmos Energy in 1997 after our merger with United Cities Gas Company. United Cities had owned 45 percent of his company, Woodward Marketing LLC. The relationship was so beneficial that we acquired the remaining interest in his company in 2001, and JD joined us as senior vice president, nonutility operations. He significantly expanded our gas marketing business into 22 states and developed our pipeline and storage operations into a separate business segment that is making major contributions to our earnings. We are greatly indebted to him for all that he did to help Atmos Energy grow and succeed. We wish JD and his wife, Linda, much happiness.

**Mark H. Johnson**—who joined Woodward Marketing in 1992 as vice president of marketing and operations, succeeded JD Woodward as senior vice president, nonutility operations, and as a member of our Management Committee. Mark, a petroleum engineer by training, is a highly experienced leader in gas marketing, trading, storage and financial hedging. He previously had served in a number of executive positions with Woodward Marketing and Atmos Energy Marketing. He brings a dynamic style and clear focus to his job.

**R. Earl Fischer**—spent 44 years with Atmos Energy and Western Kentucky Gas (WKG) Company. He served in accounting and operational management positions at WKG, where he tirelessly promoted the state's economic development, recruiting the General Motors Corvette Assembly Plant, the Mid-America Air Park and a dozen major companies. He was promoted to president of WKG in 1989. In 1998, he was named president of our West Texas Division, then known as Energas, and later became senior vice president, utility operations. Earl led our utility operations through many changes in the industry, dealing with volatile gas prices, system conversions and major acquisitions. He has truly been dedicated to the people we serve through his extensive civic and charitable work. Larger than life, and always a lot of fun, he leaves us a living legacy in the many young managers he has selected and developed over the years. We wish Earl and his wife, Sally, all the best.

**Kim R. Cocklin**—assumed the responsibilities as senior vice president, utility operations, and a member of the Management Committee on October 1. Before joining Atmos Energy, Kim was senior vice president, general counsel and chief compliance officer for Piedmont Natural Gas Company, Inc. At Piedmont, he was responsible for all legal, governmental and community affairs, corporate communications and Sarbanes-Oxley compliance. Earlier, Kim worked for The Williams Companies for 19 years. He served as senior vice president in charge of planning, rates and regulatory, and business development for Williams Gas Pipeline and in other executive positions. Kim brings extensive experience in both the utility-distribution and gas-pipeline businesses. His management philosophy reflects our own corporate culture, making him a valuable addition to our senior management team.

Year Ended September 30

| Dollars in thousands, except per share data | 2006 | 2005 | Change |
|---|---|---|---|
| Operating revenues | $ 6,152,363 | $ 4,961,873 | 24.0% |
| Gross profit | $ 1,216,570 | $ 1,117,637 | 8.9% |
| Utility net income | $ 53,002 | $ 81,117 | -34.7% |
| Natural gas marketing net income | 58,566 | 23,404 | 150.2% |
| Pipeline and storage net income | 35,624 | 30,599 | 16.4% |
| Other nonutility net income | 545 | 665 | -18.0% |
| Total | $ 147,737 | $ 135,785 | 8.8% |
| Total assets | $ 5,719,547 | $ 5,653,527 | 1.2% |
| Total capitalization* | $ 3,828,460 | $ 3,785,526 | 1.1% |
| Net income per share–diluted | $ 1.82 | $ 1.72 | 5.8% |
| Cash dividends per share | $ 1.26 | $ 1.24 | 1.6% |
| Book value per share at end of year | $ 20.16 | $ 19.90 | 1.3% |
| Consolidated utility segment throughput (MMcf) | 393,995 | 411,134 | -4.2% |
| Consolidated natural gas marketing segment throughput (MMcf) | 283,962 | 238,097 | 19.3% |
| Consolidated pipeline and storage segment transportation volumes (MMcf) | 420,217 | 383,377 | 9.6% |
| Heating degree days | 2,527 | 2,587 | -2.3% |
| Degree days as a percentage of normal | 87% | 89% | -2.2% |
| Meters in service at end of year | 3,181,199 | 3,157,840 | 0.7% |
| Return on average shareholders' equity | 8.9% | 9.0% | -1.1% |
| Shareholders' equity as a percentage of total capitalization (including short-term debt) at end of year | 39.1% | 40.7% | -3.9% |
| Shareholders of record | 24,690 | 26,242 | -5.9% |
| Weighted average shares outstanding–diluted (000s) | 81,390 | 79,012 | 3.0% |

*Total capitalization represents the sum of shareholders' equity and long-term debt, excluding current maturities.

## SUMMARY ANNUAL REPORT

The financial information presented in this report about Atmos Energy Corporation is condensed. Our complete financial statements, including notes as well as management's discussion and analysis of financial condition and results of operations, are presented in our *Annual Report on Form 10-K*. Atmos Energy's chief executive officer and its chief financial officer have executed all certifications with respect to the financial statements contained therein and have completed management's report on internal control over financial reporting, which are required under the Sarbanes-Oxley Act of 2002 and all related rules and regulations of the Securities and Exchange Commission. Investors may request, without charge, our *Annual Report on Form 10-K* for the fiscal year ended September 30, 2006, by calling Shareholder Relations at 972-855-3729 between 8 a.m. and 5 p.m. Central time. Our Form 10-K also is available on Atmos Energy's Web site at www.atmosenergy.com. Additional investor information is presented on page 32 of this report.





Year Ended September 30

| | 2006 | 2005 |
|---|---|---|
| **Meters in service** | | |
| Residential | 2,886,042 | 2,862,822 |
| Commercial | 275,577 | 274,536 |
| Industrial | 2,661 | 2,715 |
| Agricultural | 8,714 | 9,639 |
| Public authority and other | 8,205 | 8,128 |
| Total meters | 3,181,199 | 3,157,840 |
| **Heating degree days** | | |
| Actual (weighted average) | 2,527 | 2,587 |
| Percent of normal | 87% | 89% |
| **Utility sales volumes (MMcf)** | | |
| Residential | 144,780 | 162,016 |
| Commercial | 87,006 | 92,401 |
| Industrial | 26,161 | 29,434 |
| Agricultural | 5,629 | 3,348 |
| Public authority and other | 8,457 | 9,084 |
| Total | 272,033 | 296,283 |
| **Utility transportation volumes (MMcf)** | 126,960 | 122,098 |
| **Total utility throughput (MMcf)** | 398,993 | 418,381 |
| **Intersegment activity (MMcf)** | (4,998) | (7,247) |
| **Consolidated utility throughput (MMcf)** | 393,995 | 411,134 |
| **Consolidated natural gas marketing throughput (MMcf)** | 283,962 | 238,097 |
| **Consolidated pipeline transportation volumes (MMcf)** | 420,217 | 383,377 |
| **Operating revenues (000s)** | | |
| Gas utility sales revenues | | |
| Residential | $ 2,068,736 | $ 1,791,172 |
| Commercial | 1,061,783 | 869,722 |
| Industrial | 276,186 | 229,649 |
| Agricultural | 40,664 | 27,889 |
| Public authority and other | 103,936 | 86,853 |
| Total gas sales revenues | 3,551,305 | 3,005,285 |
| Transportation revenues | 61,475 | 58,897 |
| Other gas revenues | 37,071 | 37,859 |
| Total utility revenues | 3,649,851 | 3,102,041 |
| Natural gas marketing revenues | 2,418,856 | 1,783,926 |
| Pipeline and storage revenues | 81,857 | 73,880 |
| Other nonutility revenues | 1,799 | 2,026 |
| **Total operating revenues (000s)** | $ 6,152,363 | $ 4,961,873 |
| **Other statistics** | | |
| Gross plant (000s) | $ 5,101,308 | $ 4,765,610 |
| Net plant (000s) | $ 3,629,156 | $ 3,374,367 |
| Miles of pipe | 81,996 | 81,604 |
| Employees | 4,632 | 4,543 |

## CONDENSED CONSOLIDATED BALANCE SHEETS

September 30

| Dollars in thousands, except per share data | 2006 | 2005 |
|---|---|---|
| **Assets** | | |
| **Property, plant and equipment** | $ 5,026,478 | $ 4,631,684 |
| **Construction in progress** | 74,830 | 133,926 |
| | 5,101,308 | 4,765,610 |
| **Less accumulated depreciation and amortization** | 1,472,152 | 1,391,243 |
| Net property, plant and equipment | 3,629,156 | 3,374,367 |
| **Current assets** | | |
| Cash and cash equivalents | 75,815 | 40,116 |
| Cash held on deposit in margin account | 35,647 | 80,956 |
| Accounts receivable, less allowance for doubtful accounts of $13,686 in 2006 and $15,613 in 2005 | 374,629 | 454,313 |
| Gas stored underground | 461,502 | 450,807 |
| Other current assets | 169,952 | 238,238 |
| Total current assets | 1,117,545 | 1,264,430 |
| **Goodwill and intangible assets** | 738,521 | 737,787 |
| **Deferred charges and other assets** | 234,325 | 276,943 |
| | $ 5,719,547 | $ 5,653,527 |
| **Capitalization and Liabilities** | | |
| **Shareholders' equity** | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized, issued and outstanding: 2006 – 81,739,516 shares, 2005 – 80,539,401 shares | $ 409 | $ 403 |
| Additional paid-in capital | 1,467,240 | 1,426,523 |
| Accumulated other comprehensive loss | (43,850) | (3,341) |
| Retained earnings | 224,299 | 178,837 |
| Shareholders' equity | 1,648,098 | 1,602,422 |
| **Long-term debt** | 2,180,362 | 2,183,104 |
| Total capitalization | 3,828,460 | 3,785,526 |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | 345,108 | 461,314 |
| Other current liabilities | 388,451 | 503,368 |
| Short-term debt | 382,416 | 144,809 |
| Current maturities of long-term debt | 3,186 | 3,264 |
| Total current liabilities | 1,119,161 | 1,112,755 |
| **Deferred income taxes** | 306,172 | 292,207 |
| **Regulatory cost of removal obligation** | 261,376 | 263,424 |
| **Deferred credits and other liabilities** | 204,378 | 199,615 |
| | $ 5,719,547 | $ 5,653,527 |

## CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Year Ended September 30

| Dollars in thousands, except per share data | 2006 | 2005 | 2004 |
|---|---|---|---|
| **Operating revenues** | | | |
| Utility segment | $ 3,650,591 | $ 3,103,140 | $ 1,637,728 |
| Natural gas marketing segment | 3,156,524 | 2,106,278 | 1,618,602 |
| Pipeline and storage segment | 160,567 | 153,289 | 19,758 |
| Other nonutility segment | 5,898 | 5,302 | 3,393 |
| Intersegment eliminations | (821,217) | (406,136) | (359,444) |
| | 6,152,363 | 4,961,873 | 2,920,037 |
| **Purchased gas cost** | | | |
| Utility segment | 2,725,534 | 2,195,774 | 1,134,594 |
| Natural gas marketing segment | 3,025,897 | 2,044,305 | 1,571,971 |
| Pipeline and storage segment | 838 | 6,811 | 9,383 |
| Other nonutility segment | — | — | — |
| Intersegment eliminations | (816,476) | (402,654) | (358,102) |
| | 4,935,793 | 3,844,236 | 2,357,846 |
| **Gross profit** | 1,216,570 | 1,117,637 | 562,191 |
| **Operating expenses** | | | |
| Operation and maintenance | 433,418 | 416,281 | 214,470 |
| Depreciation and amortization | 185,596 | 178,005 | 96,647 |
| Taxes, other than income | 191,993 | 174,696 | 57,379 |
| Impairment of long-lived assets | 22,947 | — | — |
| Total operating expenses | 833,954 | 768,982 | 368,496 |
| **Operating income** | 382,616 | 348,655 | 193,695 |
| **Miscellaneous income** | 881 | 2,021 | 9,507 |
| **Interest charges** | 146,607 | 132,658 | 65,437 |
| Income before income taxes | 236,890 | 218,018 | 137,765 |
| **Income tax expense** | 89,153 | 82,233 | 51,538 |
| **Net income** | $ 147,737 | $ 135,785 | $ 86,227 |
| **Per share data** | | | |
| **Basic net income per share** | $ 1.83 | $ 1.73 | $ 1.60 |
| **Diluted net income per share** | $ 1.82 | $ 1.72 | $ 1.58 |
| **Weighted average shares outstanding:** | | | |
| Basic | 80,731 | 78,508 | 54,021 |
| Diluted | 81,390 | 79,012 | 54,416 |

Year Ended September 30

| Dollars in thousands | 2006 | 2005 | 2004 |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| **Net income** | $ 147,737 | $ 135,785 | $ 86,227 |
| **Adjustments to reconcile net income to net cash provided by operating activities:** | | | |
| Gain on sales of assets | — | — | (6,700) |
| Impairment of long-lived assets | 22,947 | — | — |
| Depreciation and amortization: | | | |
| Charged to depreciation and amortization | 185,596 | 178,005 | 96,647 |
| Charged to other accounts | 371 | 791 | 1,465 |
| Deferred income taxes | 86,178 | 12,669 | 36,997 |
| Other | 18,480 | 11,522 | (1,772) |
| Changes in assets and liabilities | (149,860) | 48,172 | 57,870 |
| Net cash provided by operating activities | 311,449 | 386,944 | 270,734 |
| **Cash Flows Used in Investing Activities** | | | |
| Capital expenditures | (425,324) | (333,183) | (190,285) |
| Acquisitions, net of cash received | — | (1,916,696) | (1,957) |
| Other, net | (5,767) | (2,131) | (570) |
| Proceeds from sales of assets | — | — | 27,919 |
| Net cash used in investing activities | (431,091) | (2,252,010) | (164,893) |
| **Cash Flows from Financing Activities** | | | |
| Net increase (decrease) in short-term debt | 237,607 | 144,809 | (118,595) |
| Net proceeds from issuance of long-term debt | — | 1,385,847 | 5,000 |
| Settlement of Treasury lock agreements | — | (43,770) | — |
| Repayment of long-term debt | (3,264) | (103,425) | (9,713) |
| Cash dividends paid | (102,275) | (98,978) | (66,736) |
| Issuance of common stock | 23,273 | 37,183 | 34,715 |
| Net proceeds from equity offering | — | 381,584 | 235,737 |
| Net cash provided by financing activities | 155,341 | 1,703,250 | 80,408 |
| Net increase (decrease) in cash and cash equivalents | 35,699 | (161,816) | 186,249 |
| **Cash and cash equivalents at beginning of year** | 40,116 | 201,932 | 15,683 |
| **Cash and cash equivalents at end of year** | $ 75,815 | $ 40,116 | $ 201,932 |



The Board of Directors
Atmos Energy Corporation

We have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atmos Energy Corporation at September 30, 2006 and 2005, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2006 (not presented herein); and in our report dated November 20, 2006, we expressed an unqualified opinion on those consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated financial statements is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

Ernst + Young LLP

Dallas, Texas
November 20, 2006

Year Ended September 30

| | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| **Balance Sheet Data at September 30 (000s)** | | | | | |
| Capital expenditures | $ 425,324 | $ 333,183 | $ 190,285 | $ 159,439 | $ 132,252 |
| Net property, plant and equipment | 3,629,156 | 3,374,367 | 1,722,521 | 1,624,394 | 1,380,070 |
| Working capital | (1,616) | 151,675 | 283,310 | 16,248 | (139,150) |
| Total assets | 5,719,547 | 5,653,527 | 2,912,627 | 2,625,495 | 2,059,631 |
| Shareholders' equity | 1,648,098 | 1,602,422 | 1,133,459 | 857,517 | 573,235 |
| Long-term debt, excluding current maturities | 2,180,362 | 2,183,104 | 861,311 | 862,500 | 668,959 |
| Total capitalization | 3,828,460 | 3,785,526 | 1,994,770 | 1,720,017 | 1,242,194 |
| **Income Statement Data** | | | | | |
| Operating revenues (000s) | $ 6,152,363 | $ 4,961,873 | $ 2,920,037 | $ 2,799,916 | $ 1,650,964 |
| Gross profit (000s) | 1,216,570 | 1,117,637 | 562,191 | 534,976 | 431,140 |
| Net income (000s) | 147,737 | 135,785 | 86,227 | 71,688 | 59,656 |
| Net income per diluted share | 1.82 | 1.72 | 1.58 | 1.54 | 1.45 |
| **Common Stock Data** | | | | | |
| Shares outstanding (000s) | | | | | |
| End of year | 81,740 | 80,539 | 62,800 | 51,476 | 41,676 |
| Weighted average | 81,390 | 79,012 | 54,416 | 46,496 | 41,250 |
| Cash dividends per share | $ 1.26 | $ 1.24 | $ 1.22 | $ 1.20 | $ 1.18 |
| Shareholders of record | 24,690 | 26,242 | 27,555 | 28,510 | 28,829 |
| Market price – High | $ 29.11 | $ 29.76 | $ 26.86 | $ 25.45 | $ 24.46 |
| Low | $ 25.79 | $ 24.85 | $ 23.68 | $ 20.70 | $ 18.37 |
| End of year | $ 28.55 | $ 28.25 | $ 25.19 | $ 23.94 | $ 21.50 |
| Book value per share at end of year | $ 20.16 | $ 19.90 | $ 18.05 | $ 16.66 | $ 13.75 |
| Price/Earnings ratio at end of year | 15.69 | 16.42 | 15.94 | 15.55 | 14.83 |
| Market/Book ratio at end of year | 1.42 | 1.42 | 1.40 | 1.44 | 1.56 |
| Annualized dividend yield at end of year | 4.4% | 4.4% | 4.8% | 5.0% | 5.5% |
| **Customers and Volumes (as metered)** | | | | | |
| Consolidated utility gas sales volumes (MMcf) | 272,033 | 296,283 | 173,219 | 184,512 | 145,488 |
| Consolidated utility gas transportation volumes (MMcf) | 121,962 | 114,851 | 72,814 | 63,453 | 63,053 |
| Consolidated utility throughput (MMcf) | 393,995 | 411,134 | 246,033 | 247,965 | 208,541 |
| Consolidated natural gas marketing throughput (MMcf) | 283,962 | 238,097 | 222,572 | 225,961 | 204,027 |
| Consolidated pipeline transportation volumes (MMcf) | 420,217 | 383,377 | ..... | ..... | ..... |
| Meters in service at end of year | 3,181,199 | 3,157,840 | 1,679,136 | 1,672,798 | 1,389,341 |
| Heating degree days* | 2,527 | 2,587 | 3,271 | 3,473 | 3,368 |
| Degree days as a percentage of normal | 87% | 89% | 96% | 101% | 94% |
| Utility average cost of gas per Mcf sold | $ 10.02 | $ 7.41 | $ 6.55 | $ 5.76 | $ 3.87 |
| Utility average transportation fee per Mcf | $ .49 | $ .49 | $ .36 | $ .43 | $ .41 |
| **Statistics** | | | | | |
| Return on average shareholders' equity | 8.9% | 9.0% | 9.1% | 9.9% | 9.9% |
| Number of employees | 4,632 | 4,543 | 2,864 | 2,905 | 2,338 |
| Net utility plant per meter | $ 969 | $ 927 | $ 994 | $ 930 | $ 939 |
| Utility operation and maintenance expense per meter | $ 112 | $ 110 | $ 116 | $ 115 | $ 101 |
| Meters per employee – utility | 723 | 730 | 612 | 594 | 616 |
| Times interest earned before income taxes | 2.55 | 2.59 | 3.05 | 2.75 | 2.55 |

*Heating degree days are adjusted for service areas with weather-normalized operations.







The matters discussed or incorporated by reference in this *Summary Annual Report* 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 the Company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this report or any other of the Company's documents or oral presentations, the words "anticipate," "believe," "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 discussed in this report. These risks and uncertainties are discussed in the Company's Form 10-K for the fiscal year ended September 30, 2006. Although the Company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, the Company undertakes no obligation to update or revise any of its forward-looking statements, whether as a result of new information, future events or otherwise.

# ATMOS ENERGY OFFICERS

SENIOR MANAGEMENT TEAM

**Robert W. Best**
Chairman, President and
Chief Executive Officer

**J. Patrick Reddy**
Senior Vice President and
Chief Financial Officer

**Kim R. Cocklin**
Senior Vice President,
Utility Operations

**Mark H. Johnson**
Senior Vice President,
Nonutility Operations

**Louis P. Gregory**
Senior Vice President and
General Counsel

**Wynn D. McGregor**
Senior Vice President,
Human Resources

UTILITY DIVISIONS

**J. Kevin Akers**
President,
Mississippi Division

**Richard A. Erskine**
President,
Mid-Tex Division
President,
Atmos Pipeline-Texas Division

**Gary W. Gregory**
President,
West Texas Division

**Tom S. Hawkins, Jr.**
President,
Louisiana Division

**John A. Paris**
President,
Kentucky and
Mid-States Division

**Gary L. Schlessman**
President,
Colorado-Kansas Division

NONUTILITY OPERATIONS

**Mark H. Johnson**
President,
Atmos Energy Marketing, LLC

**Ronald W. McDowell**
Vice President,
New Business Ventures

SHARED SERVICES

**Verlon R. Aston, Jr.**
Vice President,
Governmental and
Public Affairs

**Cindy A. Foor**
Vice President,
Corporate Communications

**Susan Kappes Giles**
Vice President,
Investor Relations

**Conrad E. Gruber**
Vice President,
Strategic Planning

**Dwala J. Kuhn**
Corporate Secretary

**Fred E. Meisenheimer**
Vice President and Controller

**Laurie M. Sherwood**
Vice President,
Corporate Development,
and Treasurer





# BOARD OF DIRECTORS

**Travis W. Bain II**
Chairman, Texas Custom Pools, Inc.
Plano, Texas
Board member since 1988
Committees: Work Session/Annual Meeting (Chairman), Audit, Human Resources

**Robert W. Best**
Chairman, President and Chief Executive Officer
Atmos Energy Corporation
Dallas, Texas
Board member since 1997
Committee: Executive

**Dan Busbee**
Adjunct Professor, Dedman School of Law,
Southern Methodist University
Dallas, Texas
Board member since 1988
Committees: Audit (Chairman),
Human Resources

**Richard W. Cardin**
Retired partner of Arthur Andersen LLP
Nashville, Tennessee
Board member since 1997
Committees: Audit, Nominating and
Corporate Governance

**Thomas J. Garland**
Chairman of the Tusculum Institute
for Public Leadership and Policy
Greeneville, Tennessee
Board member since 1997
Committees: Human Resources,
Work Session/Annual Meeting

**Richard K. Gordon**
General Partner, Juniper Energy LP,
Juniper Capital LP and Juniper Advisory LP
Houston, Texas
Board member since 2001
Committees: Human Resources, Nominating
and Corporate Governance

**Gene C. Koonce**
Retired Chairman of the Board, President and
Chief Executive Officer, United Cities Gas Company
Nashville, Tennessee
Board member since 1997
Committees: Human Resources (Chairman),
Executive, Work Session/Annual Meeting

**Dr. Thomas C. Meredith**
Commissioner of Mississippi Institutions
of Higher Learning
Jackson, Mississippi
Board member since 1995
Committees: Audit, Nominating and
Corporate Governance

**Phillip E. Nichol**
Retired Senior Vice President of Central Division Staff
UBS PaineWebber Incorporated
Dallas, Texas
Board member since 1985
Committees: Nominating and Corporate Governance
(Chairman), Human Resources, Work Session/
Annual Meeting

**Nancy K. Quinn**
Principal, Hanover Capital, LLC
East Hampton, New York
Board member since 2004
Committees: Audit, Nominating and
Corporate Governance

**Stephen R. Springer**
Retired Senior Vice President and
General Manager, Mid-Stream Division
The Williams Companies, Inc.
Syracuse, Indiana
Board member since 2005
Committee: Work Session/Annual Meeting

**Charles K. Vaughan**
Retired Chairman of the Board
Atmos Energy Corporation
Dallas, Texas
Board member since 1983
Committee: Executive (Chairman)

**Richard Ware II**
President, Amarillo National Bank
Amarillo, Texas
Board member since 1994
Committees: Nominating and Corporate
Governance, Work Session/Annual Meeting

**Lee E. Schlessman**
Honorary Director
President, Dolo Investment Company
Denver, Colorado
Retired from Board in 1998

## CORPORATE INFORMATION

COMMON STOCK LISTING

New York Stock Exchange. Trading symbol: ATO

STOCK TRANSFER AGENT AND REGISTRAR

American Stock Transfer and Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038
800-543-3038

To inquire about your Atmos Energy stock, please call AST at the telephone number above. You may use the agent's interactive voice response system 24 hours a day to learn about transferring stock or to check your recent account activity—all without the assistance of a customer service representative. Please have available your Atmos Energy shareholder account number and your Social Security or federal taxpayer ID number.

To speak to an AST customer service representative, please call the same number between 8 a.m. and 7 p.m. Eastern time, Monday through Thursday, or 8 a.m. to 5 p.m. Eastern time on Friday.

You also may send an e-mail message on our agent's Web site at http://www.amstock.com. Please refer to Atmos Energy in your e-mail and include your Atmos Energy shareholder account number and your Social Security or federal taxpayer ID number.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young LLP
2100 Ross Avenue, Suite 1500
Dallas, Texas 75201
214-969-8000

FORM 10-K

Atmos Energy Corporation's *Annual Report on Form 10-K* is available at no charge from Shareholder Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205 or by calling 972-855-3729 between 8 a.m. and 5 p.m. Central time. Atmos Energy's Form 10-K also may be viewed on Atmos Energy's Web site at http://www.atmosenergy.com.

ANNUAL MEETING OF SHAREHOLDERS

The 2007 Annual Meeting of Shareholders will be held in the Symphony Ballroom at the Loews Vanderbilt Hotel, 2100 West End Avenue, Nashville, Tennessee 37203 on Wednesday, February 7, 2007, at 11 a.m. Central time.

DIRECT STOCK PURCHASE PLAN

Atmos Energy Corporation has a Direct Stock Purchase Plan that is available to all investors. For an Enrollment Application Form and a Plan Prospectus, please call AST at 800-543-3038. The Prospectus is also available on the Internet at http://www.atmosenergy.com. You may also obtain information by writing to Shareholder Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205.

This is not an offer to sell, or a solicitation to buy, any securities of Atmos Energy Corporation. Shares of Atmos Energy common stock purchased through the Direct Stock Purchase Plan will be offered only by Prospectus.

ATMOS ENERGY ON THE INTERNET

Information about Atmos Energy is available on the Internet at http://www.atmosenergy.com. Our Web site includes news releases, current and historical financial reports, other investor data, corporate governance documents, management biographies, customer information and facts about Atmos Energy's operations.

ATMOS ENERGY CORPORATION CONTACTS

To contact Atmos Energy's Shareholder Relations, call 972-855-3729 between 8 a.m. and 5 p.m. Central time or send an e-mail message to InvestorRelations@atmosenergy.com.

Securities analysts and investment managers, please contact:

Susan Kappes Giles
Vice President, Investor Relations
972-855-3729 972-855-3040 (fax)
InvestorRelations@atmosenergy.com



You can view this *Summary Annual Report*, our *Annual Report on Form 10-K* and other financial documents for fiscal 2006 and previous years on our Web site at www.atmosenergy.com.

If you are a shareholder who would like to receive our *Summary Annual Report* and other company documents in the future electronically, please sign up for electronic distribution. It's convenient and easy and will save costs in producing and distributing these materials.

To receive these documents over the Internet next year, please visit www.amstock.com and access your account to give your consent. Please remember that accessing the *Summary Annual Report* and other company documents over the Internet may result in charges to you from your Internet service provider or telephone company.

*Cover: Atmos Energy has changed in size and technology since its origins in the horse-and-wagon era a century ago. However, its mission of service remains as central as ever, as represented by Operations Manager Lou Ann Goldie, General Plant Operator Jerry Christensen, Human Resources Analyst Amy Kuan and Operations Supervisor Roy Moss.*

Atmos Energy Corporation P.O. Box 650205 Dallas, Texas 75265-0205 www.atmosenergy.com 972-934-9227

# UNITED STATES SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# Form 10-K

**(Mark One)**

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

**For the fiscal year ended September 30, 2006**

**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)* |

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

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common stock, No Par Value | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act:**
**None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2006, was $2,064,662,421.

As of November 8, 2006, the registrant had 81,823,767 shares of common stock outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 7, 2007 are incorporated by reference into Part III of this report.

## TABLE OF CONTENTS

## GLOSSARY OF KEY TERMS

| | |
|---|---|
| AEC | Atmos Energy Corporation |
| AEH | Atmos Energy Holdings, Inc. |
| AEM | Atmos Energy Marketing, LLC |
| AES | Atmos Energy Services, LLC |
| APB | Accounting Principles Board |
| APS | Atmos Pipeline and Storage, LLC |
| ATO | Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange |
| Bcf | Billion cubic feet |
| COSO | Committee of Sponsoring Organizations of the Treadway Commission |
| EITF | Emerging Issues Task Force |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FIN | FASB Interpretation |
| Fitch | Fitch Ratings, Ltd. |
| FSP | FASB Staff Position |
| GRIP | Gas Reliability Infrastructure Program |
| Heritage | Heritage Propane Partners, L.P. |
| iFERC | Inside FERC |
| KPSC | Kentucky Public Service Commission |
| LGS | Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001 |
| LPSC | Louisiana Public Service Commission |
| Mcf | Thousand cubic feet |
| MDWQ | Maximum daily withdrawal quantity |
| MMcf | Million cubic feet |
| Moody's | Moody's Investor Services, Inc. |
| MPSC | Mississippi Public Service Commission |
| MVG | Mississippi Valley Gas Company, which was acquired December 3, 2002 |
| NYMEX | New York Mercantile Exchange, Inc. |
| NYSE | New York Stock Exchange |
| RRC | Railroad Commission of Texas |
| RSC | Rate Stabilization Clause |
| S&P | Standard & Poor's Corporation |
| SEC | United States Securities and Exchange Commission |
| SFAS | Statement of Financial Accounting Standards |
| TXU Gas | TXU Gas Company, which was acquired on October 1, 2004 |
| USP | U.S. Propane, L.P. |
| VCC | Virginia Corporation Commission |
| WNA | Weather Normalization Adjustment |

## PART I

The terms "we," "our," "us," "Atmos" and "Atmos Energy" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

### ITEM 1. *Business*

#### Overview

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. We are one of the country's largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2006, we distributed natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our seven regulated utility divisions, which covered service areas in 12 states. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, we transport natural gas for others through our distribution system.

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

We were organized under the laws of Texas in 1983 as Energas Company for the purpose of owning and operating the natural gas distribution business of Pioneer Corporation in Texas. In September 1988, we changed our name to Atmos Energy Corporation. As a result of the merger with United Cities Gas Company in July 1997, we also became incorporated in Virginia.

#### Operating Segments

Our operations are divided into four segments:

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

#### Strategy

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our natural gas utility and nonutility businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

Over the last five years, we have primarily grown through two significant acquisitions, our acquisition in December 2002 of Mississippi Valley Gas Company (MVG) and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas).

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth while operating our utility operations efficiently by managing our operating and maintenance expenses and leveraging our technology, such as our 24-hour call centers, to achieve more efficient operations. In addition, we have focused on regulatory rate proceedings to increase revenue as our costs increase and mitigated weather-related risks through weather-normalized rates that now apply to most of our service areas. We have also strengthened our nonutility businesses by increasing gross profit margins, actively pursuing opportunities to increase the amount of storage available to us and expanding commercial opportunities in our pipeline and storage segment.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

**Utility Segment Overview**

We operated our utility segment through the following seven regulated natural gas utility divisions during the year ended September 30, 2006:

- Atmos Energy Colorado-Kansas Division,
- Atmos Energy Kentucky Division,
- Atmos Energy Louisiana Division,
- Atmos Energy Mid-States Division,
- Atmos Energy Mid-Tex Division,
- Atmos Energy Mississippi Division and
- Atmos Energy West Texas Division.

Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

Our natural gas utility distribution business is seasonal and dependent on weather conditions in our service areas. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months.

In addition to weather, our financial results are affected by the cost of natural gas and economic conditions in the areas that we serve. Higher gas costs, which we are generally able to pass through to our customers under purchased gas adjustment clauses, may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

The effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which are now approved by the regulators for over 90 percent of residential and commercial meters in our service areas. WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

Prior to October 1, 2006, our largest division, the Mid-Tex Division, did not have WNA. However, its operations benefited from a rate structure that combined a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provided for the recovery of most of our fixed costs for such operations under most weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In May 2006, the Mid-Tex Division filed a Statement of Intent seeking additional annual revenues of $60 million and several rate design changes including WNA. In July 2006, the Railroad Commission of Texas

(RRC) approved an interim and a permanent WNA, effective October 1, 2006 for the Mid-Tex Division. The agreement provided that the interim WNA will be based on the use of 30 years of weather history, while the permanent WNA will allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA will also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case. Additionally, in May 2006, we agreed to a settlement with the Louisiana Public Service Commission (LPSC) that authorized the implementation of WNA in our Louisiana Division effective December 1, 2006.

As of September 30, 2006 we had, or received regulatory approvals for WNA for our customer meters in the following service areas for the following periods:

| | |
|---|---|
| Georgia | October — May |
| Kansas | October — May |
| Kentucky | November — April |
| Louisiana[1] | December — March |
| Mid-Tex[1] | October — May |
| Mississippi | November — April |
| Tennessee | November — April |
| Amarillo, Texas | October — May |
| West Texas | October — May |
| Lubbock, Texas | October — May |
| Virginia | January — December |

[1] Effective beginning with the 2006-2007 winter heating season.

Our natural gas supply comes from a variety of third-party providers and from gas held in storage. We anticipate that the natural gas supply for the upcoming winter heating season will be provided by a variety of suppliers, including independent producers, marketers and pipeline companies, in addition to withdrawals of gas from storage. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements. We also contract for storage service in underground storage facilities on many of the interstate pipelines serving us. We estimate the peak-day availability of natural gas supply from long-term contracts, short-term contracts and withdrawals from underground storage to be approximately 4.2 Bcf. The peak-day demand for our utility operations in fiscal 2006 was on December 8, 2005, when sales to customers reached approximately 3.4 Bcf.

Supply arrangements are contracted from our suppliers on a firm basis with various terms at market prices. The firm supply consists of both base load and swing supply quantities. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions. Except for local production purchases, we select suppliers through a competitive bidding process by requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers during fiscal 2006 were Anadarko Energy Services, BP Energy Company, Chesapeake Energy Marketing, Inc., ConocoPhillips Company, Cross Timbers Energy Services, Inc., Devon Gas Services, L.P., Enbridge Marketing (US) L.P., PPM Energy, Inc., Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments.

Also, to maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state statutes or regulations. Our customers' demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We anticipate no problems with obtaining additional gas supply as needed for our customers.

We receive gas deliveries for all of our utility divisions, except for our Mid-Tex Division, through 37 pipeline transportation companies, both interstate and intrastate, to satisfy our natural gas needs. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered by our Atmos Pipeline — Texas Division.

The following is a brief description of our seven natural gas utility divisions. Additional information for our natural gas utility divisions is presented under the caption "Operating Statistics".

*Atmos Energy Colorado-Kansas Division.* Our Colorado-Kansas Division operates in Colorado, Kansas and the southwestern corner of Missouri and is regulated by each respective state's public service commission with respect to accounting, rates and charges, operating matters and the issuance of securities. We operate under terms of non-exclusive franchises granted by the various cities. Rates in our Kansas service area are subject to WNA. The principal transporters of the Colorado-Kansas Division's gas supply requirements are Colorado Interstate Gas Company, Northwest Pipeline, Public Service Company of Colorado and Southern Star Central Pipeline. Additionally, the Colorado-Kansas Division purchases substantial volumes from producers that are connected directly to its distribution system.

*Atmos Energy Kentucky Division.* Our Kentucky Division operates in Kentucky and is regulated by the Kentucky Public Service Commission (KPSC), which regulates utility services, rates, issuance of securities and other matters. We operate in various incorporated cities pursuant to non-exclusive franchises granted by these cities. The sale of natural gas for use as vehicle fuel in Kentucky is unregulated. In February 2006, the KPSC approved our request to continue the performance-based ratemaking mechanism for an additional five-year period. Under the performance-based mechanism, we and our customers jointly share in any actual gas cost savings achieved when compared to pre-determined benchmarks. Our rates are also subject to WNA. The Kentucky Division's gas supply is delivered primarily by Midwestern Pipeline, Tennessee Gas Pipeline Company, Texas Gas Transmission LLC and Trunkline Gas Company. As noted below, this division was combined with the Mid-States Division effective October 1, 2006.

*Atmos Energy Louisiana Division.* Our Louisiana Division operates in Louisiana and serves the metropolitan area of Monroe, the suburban areas of New Orleans and western Louisiana. Our Louisiana Division is regulated by the Louisiana Public Service Commission, which regulates utility services, rates and other matters. We operate most of our service areas pursuant to a non-exclusive franchise granted by the governing authority of each area. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our natural gas marketing segment. Effective beginning with the 2006-2007 winter heating season, rates in our Louisiana service area will be subject to WNA. The principal transporters of the Louisiana Division's gas supply requirements are Acadian Pipeline, Gulf South, Louisiana Intrastate Gas Company, Texas Gas Transmission LLC and Trans Louisiana Gas Pipeline, Inc., a subsidiary of Atmos Pipeline and Storage, LLC.

*Atmos Energy Mid-States Division.* Our Mid-States Division operates in Georgia, Illinois, Iowa, Missouri, Tennessee and Virginia. In each of these states, our rates, services and operations as a natural gas distribution company are subject to general regulation by each state's public service commission. We operate in each community, where necessary, under a franchise granted by the municipality for a fixed term of years. In Tennessee and Georgia, we have WNA and a performance-based rate program, which provides incentives for us to find ways to lower costs and share the cost savings with our customers. We have WNA in our Virginia service area that covers the entire year. Our Mid-States Division is served by 13 interstate pipelines; however, the majority of the volumes are transported through Columbia Gulf, East Tennessee Pipeline, Southern Natural Gas and Tennessee Gas Pipeline. The Kentucky Division was combined with the Mid-States Division effective October 1, 2006.

*Atmos Energy Mid-Tex Division.* Our Mid-Tex Division includes the natural gas distribution operations that operate in the north-central, eastern and western parts of Texas. The Mid-Tex Division purchases, distributes and sells natural gas in approximately 550 cities and towns, including the 11-county Dallas/Fort Worth metropolitan area. This division currently operates under a system-wide rate structure. The governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The RRC has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. Effective beginning with the 2006-2007 winter heating season, rates in our Mid-Tex service area will be subject to WNA.

*Atmos Energy Mississippi Division.* Our Atmos Energy Mississippi Division operates in Mississippi and is regulated by the Mississippi Public Service Commission (MPSC) with respect to rates, services and operations. We operate under non-exclusive franchises granted by the municipalities we serve. Through fiscal 2005, we operated under a rate structure that allowed us, over a five-year period, to recover a portion of our integration costs associated with the MVG acquisition and operations and maintenance costs in excess of an agreed-upon benchmark. In addition, we were required to file for rate adjustments based on our expenses every six months. Effective October 1, 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, beginning October 1, 2005, we moved from a semi-annual filing process to an annual filing process. We also have WNA in Mississippi. This division's gas supply is delivered primarily by Gulf South Pipeline Company, Tennessee Gas Pipeline Company, Southern Natural Gas Company, Texas Eastern Transmission, Texas Gas Transmission LLC, Trunkline Gas Co. LLC and Enbridge Marketing LP.

*Atmos Energy West Texas Division.* Our West Texas Division operates in Texas in three primary service areas: the Amarillo service area, the Lubbock service area and the West Texas service area. Similar to our Mid-Tex Division, the governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The RRC has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. We have WNA in each of our service areas. Our West Texas Division receives transportation service from ONEOK Pipeline. In addition, the West Texas Division purchases a significant portion of its natural gas supply from Pioneer Natural Resources, which is connected directly to our Amarillo, Texas, distribution system.

**Natural Gas Marketing Segment Overview**

Our natural gas marketing and other nonutility segments, which are organized under Atmos Energy Holdings, Inc. (AEH), have operations in 22 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C., which was renamed Atmos Energy Marketing, LLC (AEM).

We acquired a 45 percent interest in Woodward Marketing, L.L.C. in July 1997 as a result of the merger of Atmos Energy and United Cities Gas Company, which had acquired that interest in May 1995. In April

2001, we acquired the remaining 55 percent interest that we did not own for 1,423,193 restricted shares of our common stock.

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services primarily consist of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price management through the use of derivative products. We use proprietary and customer-owned transportation and storage assets to provide the various services our customers request. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we participate in natural gas storage transactions in which we seek to capture the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM's management of natural gas requirements involves the sale of natural gas and the management of storage and transportation supplies under contracts with customers generally having one to two year terms. AEM also sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms from 30 days to two years. At September 30, 2006, AEM had a total of 679 industrial, 73 municipal and 289 other customers.

**Pipeline and Storage Segment Overview**

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline and lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. Both of these services are primarily offered on our Atmos Pipeline — Texas system. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

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

In May 2006, APS announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky. Referred to as the Straight Creek Project, the new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. In October 2006, the Federal Energy Regulatory Commission (FERC) issued a declaratory order finding that the Straight Creek Project will be exempt from FERC jurisdiction. The joint venture provides APS the opportunity to apply its expertise to the upstream gathering business.

**Other Nonutility Segment Overview**

Our other nonutility segment consists primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. which are wholly-owned by our subsidiary, Atmos Energy Holdings, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services, which began in April 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices in exchange for revenues that are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Through January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of Atmos Energy Holdings, Inc., owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with other utility companies to own a limited partnership interest in Heritage Propane Partners, L.P. (Heritage), a publicly-traded marketer of propane through a nationwide retail distribution network. During fiscal 2004, we sold our interest in USP and Heritage. As a result of these transactions, we no longer have an interest in the propane business.

## Operating Statistics

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for each of the five fiscal years from 2002 through 2006.

### *Utility Sales and Statistical Data*

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005[1] | 2004 | 2003[1] | 2002 |
| **METERS IN SERVICE, end of year** | | | | | |
| Residential | 2,886,042 | 2,862,822 | 1,506,777 | 1,498,586 | 1,247,247 |
| Commercial | 275,577 | 274,536 | 151,381 | 151,008 | 122,156 |
| Industrial | 2,661 | 2,715 | 2,436 | 3,799 | 2,118 |
| Agricultural | 8,714 | 9,639 | 8,397 | 9,514 | 10,576 |
| Public authority and other | 8,205 | 8,128 | 10,145 | 9,891 | 7,244 |
| Total meters | 3,181,199 | 3,157,840 | 1,679,136 | 1,672,798 | 1,389,341 |
| **HEATING DEGREE DAYS[2]** | | | | | |
| Actual (weighted average) | 2,527 | 2,587 | 3,271 | 3,473 | 3,368 |
| Percent of normal | 87% | 89% | 96% | 101% | 94% |
| **UTILITY SALES VOLUMES — MMcf[3]** | | | | | |
| Gas Sales Volumes | | | | | |
| Residential | 144,780 | 162,016 | 92,208 | 97,953 | 77,386 |
| Commercial | 87,006 | 92,401 | 44,226 | 45,611 | 35,796 |
| Industrial | 26,161 | 29,434 | 22,330 | 23,738 | 14,499 |
| Agricultural | 5,629 | 3,348 | 4,642 | 7,884 | 10,988 |
| Public authority and other | 8,457 | 9,084 | 9,813 | 9,326 | 5,875 |
| Total gas sales volumes | 272,033 | 296,283 | 173,219 | 184,512 | 144,544 |
| Utility transportation volumes | 126,960 | 122,098 | 87,746 | 70,159 | 69,589 |
| Total utility throughput | 398,993 | 418,381 | 260,965 | 254,671 | 214,133 |
| **UTILITY OPERATING REVENUES (000's)[3]** | | | | | |
| Gas Sales Revenues | | | | | |
| Residential | $2,068,736 | $1,791,172 | $ 923,773 | $ 873,375 | $ 535,981 |
| Commercial | 1,061,783 | 869,722 | 400,704 | 367,961 | 221,728 |
| Industrial | 276,186 | 229,649 | 155,336 | 151,969 | 70,164 |
| Agricultural | 40,664 | 27,889 | 31,851 | 48,625 | 37,951 |
| Public authority and other | 103,936 | 86,853 | 77,178 | 65,921 | 31,731 |
| Total utility gas sales revenues | 3,551,305 | 3,005,285 | 1,588,842 | 1,507,851 | 897,555 |
| Transportation revenues | 62,215 | 59,996 | 31,714 | 30,461 | 28,786 |
| Other gas revenues | 37,071 | 37,859 | 17,172 | 15,770 | 11,185 |
| Total utility operating revenues | $3,650,591 | $3,103,140 | $1,637,728 | $1,554,082 | $ 937,526 |
| Utility average transportation revenue per Mcf | $ 0.49 | $ 0.49 | $ 0.36 | $ 0.43 | $ 0.41 |
| Utility average cost of gas per Mcf sold | $ 10.02 | $ 7.41 | $ 6.55 | $ 5.76 | $ 3.87 |
| Employees | 4,402 | 4,327 | 2,742 | 2,817 | 2,255 |

See footnotes following these tables.

### *Utility Sales and Statistical Data By Division*

| | Year Ended September 30, 2006 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Colorado-Kansas | Kentucky | Louisiana | Mid-States | West Texas | Mississippi | Mid-Tex | Other[4] | Total Utility |
| **METERS IN SERVICE** | | | | | | | | | |
| Residential | 213,566 | 158,408 | 330,694 | 277,998 | 273,520 | 241,406 | 1,390,450 | — | 2,886,042 |
| Commercial | 21,440 | 18,228 | 23,108 | 36,686 | 25,984 | 27,868 | 122,263 | — | 275,577 |
| Industrial | 84 | 240 | — | 681 | 808 | 643 | 205 | — | 2,661 |
| Agricultural | 312 | — | — | — | 8,402 | — | — | — | 8,714 |
| Public authority and other | 543 | 1,637 | — | 1,034 | 2,166 | 2,825 | — | — | 8,205 |
| Total | 235,945 | 178,513 | 353,802 | 316,399 | 310,880 | 272,742 | 1,512,918 | — | 3,181,199 |
| **HEATING DEGREE DAYS[2]** | | | | | | | | | |
| Actual | 5,466 | 4,349 | 1,319 | 3,515 | 3,561 | 2,757 | 1,697 | — | 2,527 |
| Percent of normal | 99% | 100% | 78% | 95% | 100% | 102% | 72% | — | 87% |
| **SALES VOLUMES — MMcf[3]** | | | | | | | | | |
| Gas Sales Volumes | | | | | | | | | |
| Residential | 15,113 | 9,249 | 12,131 | 15,065 | 15,609 | 12,601 | 65,012 | — | 144,780 |
| Commercial | 5,901 | 4,526 | 6,944 | 11,328 | 6,309 | 6,440 | 45,558 | — | 87,006 |
| Industrial | 419 | 1,830 | — | 6,945 | 3,933 | 8,250 | 4,784 | — | 26,161 |
| Agricultural | 619 | — | — | — | 5,010 | — | — | — | 5,629 |
| Public authority and other | 1,390 | 1,237 | — | 226 | 1,962 | 3,642 | — | — | 8,457 |
| Total | 23,442 | 16,842 | 19,075 | 33,564 | 32,823 | 30,933 | 115,354 | — | 272,033 |
| Transportation Volumes | 9,680 | 25,871 | 6,310 | 20,654 | 15,135 | 1,702 | 47,608 | — | 126,960 |
| Total Throughput | 33,122 | 42,713 | 25,385 | 54,218 | 47,958 | 32,635 | 162,962 | — | 398,993 |
| **OPERATING MARGIN (000's)[3]** | $ 71,000 | $ 50,271 | $ 98,502 | $106,742 | $ 93,693 | $ 92,515 | $ 412,334 | $ — | $ 925,057 |
| **OPERATING EXPENSES (000's)[3]** | | | | | | | | | |
| Operation and maintenance | $ 28,235 | $ 19,874 | $ 40,741 | $ 38,148 | $ 33,332 | $ 44,533 | $ 154,412 | $ (1,756) | $ 357,519 |
| Depreciation and amortization | $ 13,578 | $ 11,636 | $ 21,201 | $ 22,172 | $ 13,690 | $ 10,596 | $ 74,375 | $ (2,755) | $ 164,493 |
| Taxes, other than income | $ 6,663 | $ 4,423 | $ 8,788 | $ 10,867 | $ 21,509 | $ 14,110 | $ 111,844 | $ — | $ 178,204 |
| Impairment of long-lived assets | $ — | $ — | $ — | $ — | $ 22,947 | $ — | $ — | $ — | $ 22,947 |
| **OPERATING INCOME (000's)[3]** | $ 22,524 | $ 14,338 | $ 27,772 | $ 35,555 | $ 2,215 | $ 23,276 | $ 71,703 | $ 4,511 | $ 201,894 |
| **CAPITAL EXPENDITURES (000's)** | $ 19,466 | $ 16,645 | $ 32,218 | $ 38,307 | $ 27,374 | $ 15,389 | $ 134,762 | $ 23,581 | $ 307,742 |
| **PROPERTY, PLANT AND EQUIPMENT, NET (000's)** | $252,584 | $190,959 | $328,310 | $436,916 | $253,086 | $226,690 | $1,262,516 | $132,240 | $3,083,301 |
| **OTHER STATISTICS, at year end** | | | | | | | | | |
| Miles of pipe | 6,601 | 3,937 | 8,214 | 8,015 | 14,831 | 6,415 | 27,856 | — | 75,869 |
| Employees | 263 | 220 | 412 | 416 | 341 | 437 | 1,458 | 855 | 4,402 |

See footnotes following these tables.

| | Year Ended September 30, 2005 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Colorado-Kansas | Kentucky | Louisiana | Mid-States | West Texas | Mississippi | Mid-Tex | Other[4] | Total Utility |
| **METERS IN SERVICE** | | | | | | | | | |
| Residential | 209,321 | 159,216 | 348,576 | 276,667 | 267,278 | 244,136 | 1,357,628 | — | 2,862,822 |
| Commercial | 20,914 | 18,350 | 23,850 | 36,519 | 25,410 | 28,350 | 121,143 | — | 274,536 |
| Industrial | 81 | 239 | — | 684 | 816 | 664 | 231 | — | 2,715 |
| Agricultural | 279 | — | — | — | 9,360 | — | — | — | 9,639 |
| Public authority and other | 476 | 1,650 | — | 1,066 | 2,139 | 2,797 | — | — | 8,128 |
| Total | 231,071 | 179,455 | 372,426 | 314,936 | 305,003 | 275,947 | 1,479,002 | — | 3,157,840 |
| **HEATING DEGREE DAYS[2]** | | | | | | | | | |
| Actual | 5,437 | 4,241 | 1,301 | 3,510 | 3,536 | 2,583 | 1,904 | — | 2,587 |
| Percent of normal | 99% | 98% | 78% | 93% | 99% | 96% | 80% | — | 89% |
| **SALES VOLUMES — MMcf[3]** | | | | | | | | | |
| Gas Sales Volumes | | | | | | | | | |
| Residential | 16,404 | 10,741 | 13,134 | 16,222 | 19,292 | 12,985 | 73,238 | — | 162,016 |
| Commercial | 5,929 | 4,891 | 6,811 | 11,806 | 7,493 | 6,711 | 48,760 | — | 92,401 |
| Industrial | 338 | 1,858 | — | 8,205 | 4,477 | 9,057 | 5,499 | — | 29,434 |
| Agricultural | 246 | — | — | — | 3,102 | — | — | — | 3,348 |
| Public authority and other | 1,355 | 1,396 | — | 241 | 2,296 | 3,796 | — | — | 9,084 |
| Total | 24,272 | 18,886 | 19,945 | 36,474 | 36,660 | 32,549 | 127,497 | — | 296,283 |
| Transportation Volumes | 8,388 | 26,066 | 7,046 | 20,142 | 12,390 | 1,309 | 46,757 | — | 122,098 |
| Total Throughput | 32,660 | 44,952 | 26,991 | 56,616 | 49,050 | 33,858 | 174,254 | — | 418,381 |
| **OPERATING MARGIN (000's)[3]** | $ 70,542 | $ 52,302 | $ 94,350 | $110,012 | $ 90,316 | $ 91,610 | $ 398,234 | $ — | $ 907,366 |
| **OPERATING EXPENSES (000's)[3]** | | | | | | | | | |
| Operation and maintenance | $ 26,679 | $ 18,618 | $ 37,994 | $ 38,427 | $ 29,701 | $ 49,241 | $ 146,449 | $ (515) | $ 346,594 |
| Depreciation and amortization | $ 13,693 | $ 11,739 | $ 21,911 | $ 23,615 | $ 13,249 | $ 10,830 | $ 64,460 | $ — | $ 159,497 |
| Taxes, other than income | $ 5,013 | $ 3,288 | $ 9,626 | $ 12,283 | $ 19,846 | $ 12,494 | $ 102,360 | $ — | $ 164,910 |
| **OPERATING INCOME (000's)[3]** | $ 25,157 | $ 18,657 | $ 24,819 | $ 35,687 | $ 27,520 | $ 19,045 | $ 84,965 | $ 515 | $ 236,365 |
| **CAPITAL EXPENDITURES (000's)** | $ 20,690 | $ 17,525 | $ 31,198 | $ 34,176 | $ 29,066 | $ 15,925 | $ 115,024 | $ 36,970 | $ 300,574 |
| **PROPERTY, PLANT AND EQUIPMENT, NET (000's)** | $244,250 | $183,931 | $318,869 | $416,825 | $263,285 | $206,511 | $1,167,425 | $125,000 | $2,926,096 |
| **OTHER STATISTICS, at year end** | | | | | | | | | |
| Miles of pipe | 6,530 | 3,908 | 8,151 | 7,958 | 15,000 | 6,356 | 33,701 | — | 81,604 |
| Employees | 267 | 236 | 421 | 412 | 346 | 467 | 1,398 | 780 | 4,327 |

See footnotes following these tables.

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

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| **CUSTOMERS, end of year** | | | | | |
| Industrial | 746 | 624 | 638 | 644 | 641 |
| Municipal | 73 | 69 | 80 | 94 | 101 |
| Other | 467 | 401 | 237 | 202 | 117 |
| Total | 1,286 | 1,094 | 955 | 940 | 859 |
| **NATURAL GAS MARKETING SALES VOLUMES — MMcf(3)** | 336,516 | 273,201 | 265,090 | 294,785 | 273,692 |
| **PIPELINE TRANSPORTATION VOLUMES — MMcf(3)** | 590,985 | 563,949 | 9,395 | 11,648 | 12,788 |
| **OPERATING REVENUES (000's)(3)** | | | | | |
| Natural gas marketing | $3,156,524 | $2,106,278 | $1,618,602 | $1,668,493 | $1,031,874 |
| Pipeline and storage | 160,567 | 153,289 | 19,758 | 20,298 | 18,720 |
| Other nonutility | 5,898 | 5,302 | 3,393 | 2,853 | 5,985 |
| Total operating revenues | $3,322,989 | $2,264,869 | $1,641,753 | $1,691,644 | $1,056,579 |
| Employees, at year end | 230 | 216 | 122 | 88 | 83 |

Notes to preceding tables:

(1) The operational and statistical information includes the operations of the Mississippi Division since the December 3, 2002 acquisition date and the Mid-Tex and Atmos Pipeline — Texas Divisions since the October 1, 2004 acquisition date.

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

(3) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.

(4) The Other column represents our utility shared services unit, which provides administrative and other support to our seven regulated utility divisions. Certain costs incurred by this unit are not allocated to our utility divisions.

### Ratemaking Activity

*Overview*

The method of determining regulated rates varies among the states in which our natural gas utility divisions operate. The regulators have the responsibility of ensuring that utilities under their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on investment. Generally, each regulatory authority reviews our rate request and establishes a rate structure intended to generate revenue sufficient to cover our costs of doing business and provide a reasonable return on invested capital.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments because they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. Additionally, some jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial hedges to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

The following table summarizes some information regarding our ratemaking jurisdictions. This information is for regulatory purposes only and may not be representative of our actual financial position.

***Jurisdictional Rate Summary***

| Division | Jurisdiction | Effective Date of Last Rate Action | Rate Base (thousands)[1] | Authorized Rate of Return[1] | Authorized Return on Equity[1] |
|---|---|---|---|---|---|
| Atmos Pipeline — Texas . . . | Texas | 5/24/04 | $417,111 | 8.258% | 10.00% |
| Colorado-Kansas . . . . . . . . . | Colorado | 7/1/05 | 84,711 | 8.95% | 11.25% |
| | Kansas | 3/1/04 | (2) | (2) | (2) |
| Kentucky . . . . . . . . . . . . . . | Kentucky | 12/21/99 | (2) | (2) | (2) |
| Louisiana . . . . . . . . . . . . . . | Trans LA | 10/1/04 | 81,645 | 9.14% | 10.50% - 11.50% |
| | LGS | 10/1/04 | 170,358 | 9.23% | 10.88% - 11.50% |
| Mid-States . . . . . . . . . . . . . | Georgia | 12/20/05 | 62,380 | 7.57% | 10.13% |
| | Illinois | 11/1/00 | 24,564 | 9.18% | 11.56% |
| | Iowa | 3/1/01 | 5,000 | (2) | 11.00% |
| | Missouri | 10/14/95 | (2) | 10.58% | 12.15% |
| | Tennessee | 11/15/95 | 111,970 | (2) | (2) |
| | Virginia | 8/1/04 | 30,672 | 8.46% - 8.96% | 9.50% - 10.50% |
| Mid-Tex . . . . . . . . . . . . . . . | Texas | 5/24/04 | 769,721 | 8.258% | 10.00% |
| Mississippi . . . . . . . . . . . . . | Mississippi | 1/1/05 | 196,801 | 8.23% | 9.80% |
| West Texas . . . . . . . . . . . . . | Amarillo | 9/1/03 | 36,844 | 9.88% | 12.00% |
| | Lubbock | 3/1/04 | 43,300 | 9.15% | 11.25% |
| | West Texas | 5/1/04 | 87,500 | 8.77% | 10.50% |

See footnotes on the following page.

| Division | Jurisdiction | Effective Date of Last Rate Action | Authorized Debt/ Equity Ratio | Bad Debt Rider[5] | WNA | Performance-Based Rate Program[3] |
|---|---|---|---|---|---|---|
| Atmos Pipeline — Texas | Texas | 5/24/04 | 50/50 | No | N/A | N/A |
| Colorado-Kansas | Colorado | 7/1/05 | 52/48 | No | No | No |
| | Kansas | 3/1/04 | (2) | Yes | Yes | No |
| Kentucky | Kentucky | 12/21/99 | (2) | No | Yes | Yes |
| Louisiana | Trans LA | 10/1/04 | 50/50 | No | (4) | No |
| | LGS | 10/1/04 | 53/47 | No | (4) | No |
| Mid-States | Georgia | 12/20/05 | 55/45 | No | Yes | Yes |
| | Illinois | 11/1/00 | 67/33 | No | No | No |
| | Iowa | 3/1/01 | 57/43 | No | No | No |
| | Missouri | 10/14/95 | (2) | No | No | No |
| | Tennessee | 11/15/95 | 56/44 | No | Yes | Yes |
| | Virginia | 8/1/04 | 52/48 | Yes | Yes | No |
| Mid-Tex | Texas | 5/24/04 | 50/50 | No | (4) | No |
| Mississippi | Mississippi | 1/1/05 | 47/53 | No | Yes | No |
| West Texas | Amarillo | 9/1/03 | 50/50 | Yes | Yes | No |
| | Lubbock | 3/1/04 | 50/50 | No | Yes | No |
| | West Texas | 5/1/04 | 50/50 | No | Yes | No |

(1) The rate base and authorized rate of return presented in this table are the rate base and rate of return from the last base rate case for each jurisdiction. These rate bases and rates of return are not necessarily indicative of current or future rate bases or rates of return.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) The performance-based rate program provides incentives to natural gas utilities to minimize purchased gas costs by allowing the utility and its customers to share the purchased gas cost savings.

(4) During 2006, our Louisiana and Mid-Tex Divisions received authorization to implement WNA beginning in the 2006-2007 winter heating season.

(5) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

***Recent Ratemaking Activity***

Our current rate strategy focuses on seeking rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns due to weather-related variability, declining use per customer and energy conservation, also known as decoupling. Additionally, we are seeking to stratify rates for low income households and to recover the gas cost portion of our bad debt expense.

Improving rate design is a long-term process. In the interim, we are addressing regulatory lag issues by directing discretionary capital spending to jurisdictions that permit us to recover our investment in a timely manner and filing rate cases on a more frequent basis to minimize the regulatory lag to keep our actual returns more closely aligned with our allowed returns.

Approximately 97 percent of our utility revenues in the fiscal years ended September 30, 2006, 2005 and 2004 were derived from sales at rates set by or subject to approval by local or state authorities. Net annual revenue increases resulting from ratemaking activity totaling $39.0 million, $6.3 million and $16.2 million became effective in fiscal 2006, 2005 and 2004 as summarized below:

| Division | Most Recent Effective Date | Most Recent Rate Action | Jurisdiction | Increase (Decrease) to Revenue for the Year Ended September 30 | | |
|---|---|---|---|---|---|---|
| | | | | 2006 | 2005 | 2004 |
| | | | | (In thousands) | | |
| Atmos Pipeline — Texas | 8/1/06 | GRIP[1] | Texas | $ 5,205 | $1,802 | $ — |
| Colorado-Kansas | 4/1/04 | Show Cause | Colorado | — | — | (1,900) |
| | 1/1/06 | Ad Valorem Tax | Kansas | 1,565 | — | — |
| | 3/1/04 | Rate Case | Kansas | — | — | 2,500 |
| Louisiana | 2/1/06 | Stable Rate Filing[2] | LGS | 3,326 | — | — |
| | 10/1/04 | Stable Rate Filing[2] | LGS | — | 225 | — |
| Mid-States | 8/1/04 | Rate Case | Virginia | — | — | 372 |
| | 12/20/05 | Rate Case | Georgia | 409 | — | — |
| Mid-Tex | 2/1/06 | GRIP[1] | Texas | 25,313 | — | — |
| Mississippi | (3) | Stable Rate Filing[2] | Mississippi | — | 4,300 | 10,545 |
| | 11/1/05 | Rate Restructuring | Mississippi | (600) | — | — |
| West Texas | 12/1/05 | GRIP[1] | Lubbock | 1,263 | — | — |
| | 3/1/04 | Rate Case | Lubbock | — | — | 1,525 |
| | 3/1/06 | GRIP[1] | West Texas | 2,539 | — | — |
| | 5/1/04 | Rate Case | West Texas | — | — | 3,200 |
| | | | | $39,020 | $6,327 | $16,242 |

(1) In 2003, the Texas Legislature approved the Gas Reliability Infrastructure Program (GRIP) which allows natural gas utilities the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. Natural gas utilities that enter the program will be required to file a complete rate case at least once every five years.

(2) A stable rate filing is a regulatory mechanism designed to allow us to refresh our rates on a periodic basis without filing a formal rate case.

(3) The MPSC had formerly required that we file for rate adjustments every six months. Through May 2005, rate filings were made in May and November of each year and the rate adjustments typically became effective in June and December. See further discussion under the recent ratemaking activity for our Atmos Energy Mississippi Division below.

Additionally, the following ratemaking efforts were initiated during fiscal 2006 but had not been completed as of September 30, 2006:

| Division | Rate Action | Jurisdiction | Revenue Requested |
|---|---|---|---|
| | | | (In thousands) |
| Louisiana | Stable Rate Filing[1] | LGS | $10,753 |
| Mid-States | Rate Case | Missouri | 3,396 |
| | Rate Proceeding[2] | Tennessee | 3,400 |
| Mid-Tex | System-wide Case | Texas | 60,844 |
| | | | $78,393 |

(1) The Louisiana Division has included the Rate Stabilization Clause increase in rates. The increase is subject to refund, pending final resolution of the Stable Rate Filing.

(2) The Tennessee rate proceeding was settled in October 2006. See below for information regarding the settlement.

Our recent ratemaking activity is discussed in greater detail below.

*Atmos Pipeline-Texas.* In April 2006, Atmos Pipeline — Texas made a filing under Texas' Gas Reliability Infrastructure Program (GRIP) to include in rate base approximately $21.6 million of pipeline capital expenditures incurred during calendar year 2005, which should result in additional annual revenues of approximately $3.3 million. The RRC approved this filing in July 2006 and these new charges were included in the monthly customer charge beginning in August 2006.

In September 2005, Atmos Pipeline — Texas made a GRIP filing to include in rate base approximately $10.6 million of pipeline capital expenditures incurred during calendar year 2004, which resulted in approximately $1.9 million in additional annual revenue. In December 2004, Atmos Pipeline — Texas made a GRIP filing to include in rate base approximately $12.0 million of pipeline capital expenditures made by TXU Gas during calendar year 2003, which resulted in additional annual revenues of approximately $1.8 million.

*Atmos Energy Colorado-Kansas Division.* In December 2005, the Colorado-Kansas Division filed its second annual ad valorem tax surcharge for $1.6 million. The surcharge is designed to collect Kansas property taxes in excess of the amount in the Colorado-Kansas Division's most recent general rate case. We began to bill this surcharge in January 2006.

In July 2004, the Colorado Public Utility Commission ordered us to issue a one-time credit to our Colorado customers of $1.9 million. The agreement was a result of an inquiry by the Colorado Office of Consumer Counsel related to our earnings in Colorado. The staff of the Colorado Public Utility Commission was also a party to the agreement.

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

*Atmos Energy Kentucky Division.* In February 2006, the KPSC approved the Company's request to continue its Performance Based Ratemaking (PBR) mechanism for an additional five year period. The PBR establishes predetermined gas cost benchmarks and provides incentives to the Company for purchasing gas supply below those benchmark costs.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a Motion to Dismiss with the KPSC. In February 2006, the KPSC issued an Order denying our Motion to Dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In March 2006, the KPSC set a procedural schedule for the case. The Attorney General is currently conducting discovery. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

*Atmos Energy Louisiana Division.* In September 2005, the Louisiana Public Service Commission (LPSC) consolidated several then-existing dockets. These dockets included a separate proceeding for the renewal of the Rate Stabilization Clause (RSC) for each of the LGS and TransLa Gas service areas; resolution of the outstanding 2003 RSC filing for the LGS service area; and our request for approval of a decoupling mechanism to stabilize margins in both the LGS and TransLa service areas.

On May 25, 2006, the LPSC voted to approve a settlement which included a modified WNA providing for partial decoupling, renewal of the RSC for both the LGS and TransLa service areas with provisions that will reduce regulatory lag and a refund to customers of approximately $0.4 million for the LGS service areas that previously had been deferred. The first RSC filing was in August 2006 for approximately $10.8 million, based on a test year ended December 31, 2005, for the LGS service area. The increase is subject to refund, pending final approval by the LPSC. The first filing for the TransLa service area will be made by

December 31, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007. WNA for both service areas will be in effect for an initial three-year period beginning with the winter of 2006-2007. In the third quarter of fiscal 2006, $6.2 million in deferred revenue associated with the 2003 RSC rate adjustment was recognized.

On August 29, 2005, Hurricane Katrina struck the Gulf Coast, inflicting significant damage to our eastern Louisiana operations. The hardest hit areas in our service territory were in Jefferson, St. Tammany, St. Bernard and Plaquemines parishes. Although service has been restored for many of our customers, a significant number of customers will not require gas service for some time, if ever, because of sustained damages. We began implementing new rates, subject to refund, in September 2006 that reflected the reduction of approximately 26,500 customers and included a request to recover costs attributable to Hurricane Katrina. We cannot accurately determine what regulatory actions, if any, may be taken by the regulators with respect to this filing or our ability to fully recover all costs incurred as a result of the storm.

During the second quarter of 2005, the Louisiana Division implemented a rate increase of $3.3 million in its LGS service area. This increase resulted from our RSC filing in 2004 and was subject to refund, pending the final resolution of that filing. As the rate increase was subject to refund, we did not recognize the effects of this increase in our results of operations during fiscal 2005 or the first three quarters of fiscal 2006.

During fiscal 2004, the Louisiana Public Service Commission approved tariff revisions for our LGS service area totaling $0.2 million that became effective in October 2004.

In October 2002, Atmos received written notification from the Executive Secretary of the LPSC asserting that a monthly facilities fee of approximately $0.6 million charged since July 2001 to Atmos by Trans Louisiana Gas Pipeline, Inc., a wholly-owned subsidiary of Atmos, pursuant to a contract between the parties, was excessive. The Executive Secretary asserted that all monthly facilities fees in excess of approximately $0.1 million from July 2001 should be refunded to ratepayers with interest. In October 2003, the LPSC unanimously voted to approve an agreement to allow us to charge a facilities fee of approximately $0.5 million per month (subject to future escalation) beginning November 2003 for a period of 14 years. No retroactive adjustments were required under this agreement.

*Atmos Energy Mid-States Division.* In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million. The Company is proposing to consolidate the rates for its Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. The Company is also proposing a WNA mechanism. An evidentiary hearing is scheduled to begin on November 27, 2006, with an order expected to be issued in February 2007.

In March 2006, we received notification from the Tennessee Regulatory Authority (TRA) that it disagreed with the way we calculated amounts under its performance-based rate mechanism, which resulted in a one-time $3.3 million income reduction during the second quarter of fiscal 2006. We believe the original calculations were correct and have appealed the TRA's decision.

During the third quarter of fiscal 2005, Atmos filed a rate case in its Georgia service area seeking a rate increase of $4.0 million. In December 2005, the Georgia Public Service Commission (GPSC) approved a $0.4 million increase. In January 2006, we filed an appeal of the GPSC's decision in the Superior Court of Fulton County. Oral arguments were held on September 7, 2006 before the Fulton County Superior Court. The court affirmed the commission's order. We are considering further appeal.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately $10 million per year. We responded to numerous data requests from the TRA Staff. In April 2006, the TRA Staff filed a Report and Recommendation in which it recommended that the TRA convene a contested case procedure for the purpose of establishing a fair and reasonable return. The TRA convened to consider the Staff's recommendation on May 15, 2006 and set a procedural schedule. A hearing was held from August 29, 2006 through August 31, 2006. Of the $10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved on October 27, 2006 a $6.1 million reduction to future rates.

In February 2004, the Mid-States Division filed a rate case with the Virginia Corporation Commission (VCC) to request a $1.0 million increase in our base rates, WNA and recovery of the gas cost component of bad debt expense. The VCC granted a rate increase in November 2004 of $0.4 million that was retroactively effective to July 27, 2004. Additionally, the VCC authorized WNA beginning in July 2005 and the ability to recover the gas cost component of bad debt expense.

*Atmos Energy Mid-Tex Division.* The following is a discussion of our recent ratemaking activity for our Mid-Tex Division.

Rate Case

During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require us to demonstrate that existing distribution rates in the Mid-Tex Division are just and reasonable. In May 2006, in response to these resolutions, we filed a Statement of Intent to increase rates on a division-wide basis. By agreement with the cities, the "show cause" resolutions were consolidated and became part of the Mid-Tex Division's first rate case before the RRC since we acquired the TXU Gas operations in October 2004. In this rate proceeding, we are seeking incremental annual revenues in the Mid-Tex Division of approximately $60 million and several rate design changes, including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense.

In exchange for an agreement to provide the intervening parties in the proceeding additional time to prepare for the hearing, we obtained agreement from the intervenors to implement WNA in the rates for the Mid-Tex Division for the 2006-2007 winter season, which has been approved by the RRC, and to implement WNA in the final rates in this proceeding. The hearing in this proceeding was concluded on November 17, 2006, and a decision is due from the RRC no later than April 2007. During the hearing, the principal issues raised by the cities included the Mid-Tex Division's rate of return, the reduction of rate base for the accumulated deferred federal income taxes and investment tax credits associated with the TXU Gas operations prior to our acquisition, the methodology used by us to allocate certain shared services expenses to the division, and the inclusion of certain items in operation and maintenance expenses.

In addition, under applicable statutes, the RRC is reviewing the interim rate adjustments that were previously granted in response to the Mid-Tex Division's prior GRIP filings and our acquisition of the TXU Gas operations for consistency with the public interest. Any increase that the RRC may grant in this case would be effective prospectively from the date of the final order. However, any decrease that may be ordered by the RRC would be effective from May 31, 2006 pursuant to the agreement with the intervenors for consolidation of the show cause resolutions and the Statement of Intent filing. Any disallowance related to the previously granted GRIP interim rate adjustments would be refunded to customers with interest beginning some time after the issuance of a final order in this proceeding.

While the decision of the RRC in this case cannot be predicted with certainty, we believe that we have adequately demonstrated to the RRC that the Mid-Tex Division is entitled to receive an increase in annual revenues and that the remaining rate design changes should be implemented.

GRIP Filings

In March 2006, the Mid-Tex Division made a GRIP filing to include in rate base approximately $62.2 million of distribution capital expenditures incurred during calendar year 2005, which we estimate would result in additional annual revenues of approximately $11.9 million. The RRC approved this filing in August 2006, and the new customer charges were implemented in September 2006 billings to customers.

In September 2005, the Mid-Tex Division made a GRIP filing to include in rate base approximately $29.4 million of distribution capital expenditures incurred during calendar year 2004, which currently provides additional annual revenues of approximately $6.7 million. The RRC approved this filing in January 2006, and these new charges were included in the monthly customer charge beginning in February 2006.

In December 2004, the Mid-Tex Division made a GRIP filing to include in rate base approximately $32.0 million of distribution capital expenditures made by TXU Gas during calendar year 2003, which currently provides additional annual revenues of approximately $6.7 million. New monthly customer charges were implemented in October 2005.

Other Regulatory Matters

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division has requested and received approval to refund these amounts over a six-month period beginning in November 2006.

In September 2004, the Mid-Tex Division filed its 36-Month Gas Contract Review with the RRC. This proceeding involves a review for reasonableness of gas purchases totaling $2.2 billion made by the Mid-Tex Division from November 2000 through October 2003. A hearing on this matter was held before the RRC in June 2005. The parties negotiated a unanimous settlement agreement providing for a refund of $8 million to customers over a three-year period and for reimbursement of parties' expenses without recovery from customers. The RRC approved the settlement on September 12, 2006. Refunds to customers began in the first quarter of fiscal year 2007.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The case was argued before the Travis County District Court in July 2006. The Court ruled to uphold the Commission's final order. Steps are being taken to perfect an appeal to the Court of Appeals in Travis County.

*Atmos Energy Mississippi Division.* Through the first quarter of fiscal 2005, the MPSC required that we file for rate adjustments every six months. Rate filings were made in May and November of each year and the rate adjustments typically became effective in the following July and January.

During the second quarter of fiscal 2005, we agreed with the MPSC to suspend our May 2005 semi-annual filing to allow sufficient time for us and the MPSC to undertake a comprehensive review in an effort to improve our rate design and the ratemaking process. Effective October 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, we moved from a semi-annual filing process to an annual filing process. Additionally, our WNA period begins on November 1 instead of November 15, and ends on April 30 instead of May 15. Also, we now have a fixed monthly customer base charge which makes a portion of our earnings less susceptible to usage. As part of the rate design restructuring, we agreed to reduce our rates by approximately $0.6 million. We made our first annual filing under this new structure in September 2006 requesting no change in rates.

In September 2004, the MPSC originally disallowed certain deferred costs totaling $2.8 million. In connection with the modification of our rate design described above, the MPSC decided to allow these costs, and we included these costs in our rates in October 2005.

In June 2006, the MPSC approved a pilot program whereby Trans Louisiana Gas Pipeline (TLGP) will provide asset management services to the Mississippi Division. The asset management program allows TLGP to market certain off-peak gas supply assets, such as company-owned or leased storage and pipeline capacity, on a recallable basis. In return, TLGP will share net positive benefits of the asset management program with Mississippi ratepayers. The pilot program runs from June 1, 2006 to April 30, 2007 and may be extended by the MPSC upon application by Atmos.

In October 2003, the MPSC issued a final order that denied our May 2003 request for a rate increase of $5.8 million. In January 2004, the MPSC authorized additional annual revenue of $5.9 million on our November 2003 filing, which became effective in December 2003. In September 2004, the MPSC authorized additional annualized revenue of $4.7 million on our May 2004 filing, which became effective in June 2004.

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

*Atmos Energy West Texas Division.* In September 2005, the West Texas Division made a GRIP filing to include in rate base approximately $22.6 million of distribution capital costs incurred during calendar year 2004, which should result in additional annual revenues of approximately $3.8 million. Of this amount, approximately $1.3 million related to our Lubbock jurisdiction and the remaining $2.5 million related to our West Texas jurisdiction. New charges for the filings were included in the monthly customer charge beginning May 2006. Atmos made its 2005 GRIP filings for the West Texas Division and the Lubbock Division in September 2006 requesting no change in rates.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos' West Texas Division to ensure they are just and reasonable. The requested information was provided to the city on February 28, 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

In May 2006, Atmos began receiving "show cause" ordinances from several of the cities in the West Texas Division. We made a filing in response to the ordinances on October 2, 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities that our rates are just and reasonable.

In October 2003, our West Texas Division filed a rate case in Lubbock requesting a $3.0 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. The City of Lubbock approved a $1.5 million increase effective March 2004, as well as the proposed WNA.

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

**Other Regulation**

Each of our utility divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. Our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with and are operated in substantial conformity with applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites in Tennessee, Iowa and Missouri. These claims are fully described in Note 13 to the consolidated financial statements.

FERC allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC.

**Competition**

Although our utility operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial and agricultural customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. However, higher gas prices, coupled with the electric utilities' marketing efforts, have increased competition for residential and commercial customers. In addition, our Natural Gas Marketing segment competes with other natural gas brokers in obtaining natural gas supplies for our customers.

### Employees

At September 30, 2006, we had 4,632 employees, consisting of 4,402 employees in our utility segment and 230 employees in our other segments. See "Operating Statistics — Utility Sales and Statistical Data by Division" for the number of employees by division.

### Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

### Corporate Governance

In accordance with and pursuant to relevant provisions of the Sarbanes-Oxley Act of 2002, related rules and regulations of the Securities and Exchange Commission as well as corporate governance-related listing standards of the New York Stock Exchange, the Board of Directors of the Company has adopted the Company's Corporate Governance Guidelines and revised the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, the Board of Directors has updated the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of the Company's website. We will also provide copies of such information free of charge upon request to Shareholder Relations at the address listed above.

## ITEM 1A. *Risk Factors*

Our financial and operating results are subject to a number of factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other risks may prove to be important in the future. These factors include the following:

***We are subject to regulation by each state in which we operate that affect our operations and financial results.***

Our natural gas utility business is subject to various regulated returns on its rate base in each of the 12 states in which we operate. We monitor the allowed rates of return and our effectiveness in earning such rates and initiate rate proceedings or operating changes as we believe are needed. In addition, in the normal course of the regulatory environment, assets may be placed in service and historical test periods established before rate cases that could adjust our returns can be filed. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag". In addition, rate cases involve a risk of rate reduction, and once rates have been approved, they are still subject to challenge for their reasonableness by appropriate regulatory authorities. Our debt and equity financings are also subject to approval by regulatory bodies in several states which could limit our ability to take advantage of favorable market conditions.

Our business could also be affected by deregulation initiatives, including the development of unbundling initiatives in the natural gas industry. Unbundling is the separation of the provision and pricing of local distribution gas services into discrete components. It typically focuses on the separation of the distribution and gas supply components and the resulting opening of the regulated components of sales services to alternative unregulated suppliers of those services. Although we believe that our enhanced technology and distribution system infrastructures have positively positioned us, we cannot provide assurance that there would be no significant adverse effect on our business should unbundling or further deregulation of the natural gas distribution service business occur.

***Our operations are weather sensitive.***

Our natural gas utility sales volumes and related revenues are correlated with heating requirements that result from cold winter weather. Although beginning in the 2006-2007 winter heating season, we will have weather-normalized rates for over 90 percent of our residential and commercial meters that should substantially eliminate the adverse effects of warmer-than-normal weather for meters in those service areas, our utility operating results will continue to vary with the temperatures during the winter heating season. In addition, sustained cold weather could adversely affect our natural gas marketing operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts.

***The concentration of our distribution, pipeline and storage operations in the State of Texas have increased the exposure of our operations and financial results to adverse weather, economic conditions or regulatory decisions in Texas.***

As a result of our acquisition of the distribution, pipeline and storage operations of TXU Gas in October 2004, over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are now located in the State of Texas. This concentration of our business in Texas means that our operations and financial results are subject to greater impact than before from changes in the Texas economy in general as well as the weather in our service areas of the state during the winter heating season. Our financial results in fiscal 2006 were adversely affected by warm weather in Texas. In addition, the impact of any adverse rate or other regulatory decisions by state or local regulatory authorities in Texas will also be greater. The hearing in the Mid-Tex Division's first rate case since the TXU Gas acquisition has just concluded. In the proceeding, we are seeking additional revenue and several rate design changes. A rate reduction or other significant, adverse decision by the Texas Railroad Commission in the proceeding could materially affect our financial results.

***We are subject to environmental regulation which could adversely affect our operations or financial results.***

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations. Such revised or new regulations could result in increased compliance costs or additional operating restrictions which could adversely affect our business, financial condition and results of operations.

***Our operations are exposed to market risks that are beyond our control which could adversely affect our financial results.***

Our risk management operations are subject to market risks beyond our control including market liquidity, commodity price volatility and counterparty creditworthiness.

Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices or the risk in our natural gas marketing and pipeline and storage segments which could lead to volatility in our earnings. Physical trading also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. The determination of our net open position as of any day 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. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner because the timing of the recognition of profits or losses on the hedges for financial accounting purposes does not always match up with the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Further, if the local physical markets in which we trade do not move consistently with the NYMEX futures market, we could experience increased volatility in the financial results of our natural gas marketing and pipeline and storage segments.

Our natural gas marketing and pipeline and storage segments manage margins and limit risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial derivatives. However, contractual limitations could adversely affect our ability to withdraw gas from storage which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We could also realize financial losses on our efforts to limit risk as a result of volatility in the market prices of the underlying commodities or if a counterparty fails to perform under a contract. In addition, adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract.

We are also subject to interest rate risk on our commercial paper borrowings and floating rate debt. In the past few years, we have been operating in a relatively low interest-rate environment with both short and long-term interest rates being relatively low compared to past interest rates. However, in the past two years, the Federal Reserve has taken actions that have resulted in increases in short-term interest rates. Future increases in interest rates could adversely affect our future financial results.

***The execution of our business plan could be affected by an inability to access financial markets.***

We rely upon access to both short-term and long-term capital markets to satisfy our liquidity requirements. Adverse changes in the economy or these markets, the overall health of the industries in which we operate and changes to our credit ratings could limit access to these markets, increase our cost of capital or restrict the execution of our business plan.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation (S&P), Moody's Investors Services, Inc. (Moody's) and Fitch Ratings, Ltd. (Fitch), the three credit rating agencies that rate our long-term debt securities. There can be no assurance that these rating agencies will maintain investment grade ratings for our long-term debt. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and reduce the borrowing capacity of our gas marketing affiliate. In addition, if our commercial paper ratings were lowered, it would increase the cost of commercial paper financing and could reduce or eliminate our ability to access the commercial paper markets. If we are unable to issue commercial paper, we intend to borrow under our bank credit facilities to meet our working capital needs. This would increase the cost of our working capital financing.

***Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.***

Inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. However, the ability to control expenses is an important factor that could influence future results.

Rapid increases in the price of purchased gas, which occurred recently and in some prior years, cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

***Our operations are subject to increased competition.***

In the residential and commercial customer markets, our regulated utility operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if as a result, our customer growth slows, resulting in reduced ability to make capital expenditures, or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, and agricultural customers, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our pipeline and storage operations currently face limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

***The cost of providing pension and postretirement health care benefits is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.***

We provide a cash-balance pension plan for the benefit of eligible full-time employees as well as postretirement health care benefits to eligible full-time employees. Our costs of providing such benefits is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years, and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

***Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.***

We must continually build additional capacity in our natural gas distribution system to maintain the growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. Our cash flows from operations are generally not sufficient to supply funding for all our capital expenditures including the financing of the costs of this new construction along with capital expenditures necessary to maintain our existing natural gas system. As a result, we must fund at least a portion of these costs through borrowing funds from third party lenders, the cost of which is dependent on the interest rates at the time. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

***Distributing and storing natural gas involve risks that may result in accidents and additional operating costs.***

Our natural gas distribution business involves a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We do have liability and property insurance coverage in place for many of these hazards and risks. However, because our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our financial position and results of operations could be adversely affected.

***Natural disasters and terrorist activities and other actions could adversely affect our operations or financial results.***

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may be more limited, which could increase the risk that an event could adversely affect future financial results.

## ITEM 1B. *Unresolved Staff Comments*

Not applicable.

## ITEM 2. *Properties*

### Distribution, transmission and related assets

At September 30, 2006, our utility segment owned an aggregate of 75,869 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. At September 30, 2006, our pipeline and storage segment owned 6,127 miles of gas transmission and gathering lines.

Our utility segment also holds franchises granted by the incorporated cities and towns that we serve. At September 30, 2006, we held 1,103 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire.

## Storage Assets

Our utility and pipeline and storage segments own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities:

| State | Usable Capacity (Mcf) | Cushion Gas (Mcf)[1] | Total Capacity (Mcf) | Maximum Daily Delivery Capability (Mcf) |
|---|---|---|---|---|
| *Utility Segment* | | | | |
| Kentucky | 4,442,696 | 6,322,283 | 10,764,979 | 109,100 |
| Kansas | 3,639,000 | 2,640,000 | 6,279,000 | 55,000 |
| Mississippi | 1,544,633 | 2,181,737 | 3,726,370 | 48,000 |
| Georgia | 450,000 | 50,000 | 500,000 | 30,000 |
| *Total Utility Segment* | 10,076,329 | 11,194,020 | 21,270,349 | 242,100 |
| *Pipeline and Storage Segment* | | | | |
| Texas | 39,128,475 | 13,128,025 | 52,256,500 | 1,235,000 |
| Kentucky | 3,492,900 | 3,295,000 | 6,787,900 | 71,000 |
| Louisiana | 438,583 | 300,973 | 739,556 | 56,000 |
| *Total Pipeline and Storage Segment* | 43,059,958 | 16,723,998 | 59,783,956 | 1,362,000 |
| **Total** | 53,136,287 | 27,918,018 | 81,054,305 | 1,604,100 |

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity:

| Division/Company | Contractor | Maximum Storage Quantity (MMBtu) | Maximum Daily Withdrawal Quantity (MMBtu)[1] |
|---|---|---|---|
| *Utility Segment* | | | |
| Colorado-Kansas Division | Southern Star Central Pipeline | 2,719,101 | 82,397 |
| | Tenaska Marketing Ventures | 1,000,000 | 10,400 |
| | Colorado Interstate Gas Company | 422,142 | 12,985 |
| | Kinder Morgan, Inc. | 67,500 | 1,500 |
| | Centerpoint Energy Gas Transmission | 28,500 | 950 |
| Kentucky Division | Texas Gas Transmission | 3,841,150 | 41,060 |
| | Tennessee Gas Pipeline Company | 1,313,538 | 22,698 |
| Louisiana Division | Gulf South | 1,978,020 | 98,901 |
| | Jefferson Island Storage & Hub | 600,000 | 60,000 |
| | Acadian Natural Gas Company | 33,276 | 2,234 |
| | Tennessee Gas Pipeline Company | 18,776 | 329 |
| | Southern Natural Gas Company | 12,945 | 261 |
| | Trunkline Gas Company | 3,105 | 41 |
| Mid-States Division | Atmos Energy Marketing | 1,993,543 | 16,634 |
| | Southern Natural Gas Company | 1,453,265 | 29,345 |
| | Panhandle Eastern Pipeline | 1,035,462 | 15,721 |
| | Tennessee Gas Pipeline Company | 835,674 | 20,000 |
| | Texas Eastern Transmission Company | 753,969 | 11,303 |
| | Gallagher Drilling Company[2] | 640,000 | 5,000 |
| | ANR Pipeline Company | 629,480 | 11,200 |
| | Dominion | 609,008 | 8,136 |
| | Transco | 568,674 | 12,710 |
| | Virginia Gas Pipeline Company | 380,000 | 23,000 |
| | East Tennessee | 339,900 | 52,633 |
| | Natural Gas Pipeline Company | 312,750 | 5,580 |
| | Texas Gas Transmission | 239,576 | 7,495 |
| | CMS Trunkline Gas Company | 220,455 | 2,940 |
| | MRT Energy Marketing | 137,493 | 2,395 |
| Mississippi Division | Gulf South | 1,237,500 | 61,875 |
| | Southern Natural Gas Company | 1,049,436 | 21,191 |
| | Texas Gas Transmission | 826,390 | 36,420 |
| | Texas Eastern | 518,220 | 8,637 |
| | Atmos Energy Marketing | 400,000 | 40,000 |
| | Trunkline Gas Company | 24,840 | 331 |
| | Tennessee Gas Pipeline Company | 3,394 | 113 |
| West Texas Division | ONEOK Texas Gas Storage LLP | 1,125,000 | 50,000 |
| *Total Utility Segment* | | 27,372,082 | 776,415 |

See footnotes on the following page.

| Division/Company | Contractor | Maximum Storage Quantity (MMBtu) | Maximum Daily Withdrawal Quantity (MMBtu)[1] |
|---|---|---|---|
| *Natural Gas Marketing Segment* | | | |
| Atmos Energy Marketing, LLC | | | |
| | Gulf South | 5,992,015 | 85,686 |
| | Egan | 1,500,000 | 90,000 |
| | Atmos Pipeline — Texas | 1,000,000 | 24,000 |
| | Texas Eastern Transmission Company | 544,841 | 5,532 |
| | East Tennessee | 250,000 | 12,500 |
| | National Fuel | 223,080 | 2,028 |
| | Virginia Gas Pipeline Company | 170,000 | 17,000 |
| | Dominion | 56,910 | 929 |
| *Total Natural Gas Marketing Segment* | | 9,736,846 | 237,675 |
| *Pipeline and Storage Segment* | | | |
| Trans Louisiana Gas Pipeline, Inc. | Gulf South Pipeline Company | 750,000 | 30,000 |
| | Bridgeline Gas Distribution LLC | 300,000 | 30,000 |
| *Total Pipeline and Storage Segment* | | 1,050,000 | 60,000 |
| **Total Contracted Storage Capacity** | | 38,158,928 | 1,074,090 |

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

(2) We contract for storage service in two underground storage facilities, Wiseman and Ellis, from this company.

### Other facilities

Our utility segment owns and operates one propane peak shaving plant with a total capacity of approximately 180,000 gallons that can produce an equivalent of approximately 3,300 Mcf daily.

### Offices

Our administrative offices are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. Our nonutility operations are headquartered in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

## ITEM 3. *Legal Proceedings*

See Note 13 to the consolidated financial statements.

## ITEM 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2006.

## EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2006, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

| Name | Age | Years of Service | Office Currently Held |
|---|---|---|---|
| Robert W. Best | 59 | 9 | Chairman, President and Chief Executive Officer |
| Kim R. Cocklin | 55 | — | Senior Vice President, Utility Operations |
| R. Earl Fischer | 67 | 44 | Senior Vice President, Utility Operations |
| Louis P. Gregory | 51 | 6 | Senior Vice President and General Counsel |
| Mark H. Johnson | 47 | 5 | Senior Vice President, Nonutility Operations and President, Atmos Energy Marketing, LLC |
| Wynn D. McGregor | 53 | 18 | Senior Vice President, Human Resources |
| John P. Reddy | 53 | 8 | Senior Vice President and Chief Financial Officer |

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997.

Kim R. Cocklin joined the Company in June 2006 as Senior Vice President, Utility Operations to succeed R. Earl Fischer, who retired from the Company on September 30, 2006. Prior to joining the Company, Mr. Cocklin served as Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 to May 2006. Prior to joining Piedmont, Mr. Cocklin was with Williams Gas Pipeline from 1995 to January 2003, where he served in various capacities, including serving as Vice President for rates, regulatory and business development for all of the Williams Gas pipelines from 2001 to January 2003.

R. Earl Fischer was named Senior Vice President, Utility Operations in May 2000. Mr. Fischer previously served the Company as President of the Mid-Tex Division from October 2004 to October 2005. Mr. Fischer retired from the Company on September 30, 2006.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000.

Mark H. Johnson was named Senior Vice President, Nonutility Operations in April 2006 and President of Atmos Energy Holdings, Inc., and Atmos Energy Marketing, LLC, in April 2005. Mr. Johnson previously served the Company as Vice President, Nonutility Operations from October 2005 to March 2006 and as Executive Vice President of Atmos Energy Marketing from October 2003 to March 2005. Mr. Johnson joined Atmos Energy Marketing's predecessor, Woodward Marketing, L.L.C., in 1992 as Vice President of Marketing and Operations and was later promoted to Senior Vice President of Marketing for the Midwest and Gulf Coast. Mr. Johnson succeeded JD Woodward III who retired from the Company effective April 1, 2006.

Wynn D. McGregor was named Senior Vice President, Human Resources in October 2005. He previously served the Company as Vice President, Human Resources from January 1994 to September 2005.

John P. Reddy was named Senior Vice President and Chief Financial Officer in September 2000.

## PART II

**ITEM 5.** ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2006 and 2005 are listed below. The high and low prices listed are the closing NYSE quotes for shares of our common stock:

| | 2006 | | | 2005 | | |
|---|---|---|---|---|---|---|
| | **High** | **Low** | **Dividends Paid** | **High** | **Low** | **Dividends Paid** |
| **Quarter ended:** | | | | | | |
| December 31 | $28.36 | $25.79 | $.315 | $27.43 | $24.85 | $.310 |
| March 31 | 27.00 | 26.10 | .315 | 29.09 | 26.19 | .310 |
| June 30 | 27.91 | 26.00 | .315 | 28.87 | 25.94 | .310 |
| September 30 | 29.11 | 27.96 | .315 | 29.76 | 28.23 | .310 |
| | | | $1.26 | | | $1.24 |

Dividends are payable at the discretion of our Board of Directors out of legally available funds and are also subject to restriction under the terms of our First Mortgage Bond agreement. See Note 6 to the consolidated financial statements. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2006 was 24,425. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2006 that were not registered under the Securities Act of 1933, as amended.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2006.

| | Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights | Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|
| | (a) | (b) | (c) |
| **Equity compensation plans approved by security holders:** | | | |
| Long-Term Incentive Plan | 1,017,152 | $22.57 | 731,745 |
| Long-Term Stock Plan for the Mid-States Division | — | — | 168,550 |
| **Total equity compensation plans approved by security holders** | 1,017,152 | 22.57 | 900,295 |
| **Equity compensation plans not approved by security holders** | — | — | — |
| **Total** | 1,017,152 | $22.57 | 900,295 |

## ITEM 6. *Selected Financial Data*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2006[1] | 2005[2] | 2004[3] | 2003[4] | 2002 |
| | (In thousands, except per share data and ratios) | | | | |
| **Results of Operations** | | | | | |
| Operating revenues | $6,152,363 | $4,961,873 | $2,920,037 | $2,799,916 | $1,650,964 |
| Gross profit | 1,216,570 | 1,117,637 | 562,191 | 534,976 | 431,140 |
| Operating expenses[1] | 833,954 | 768,982 | 368,496 | 347,136 | 275,809 |
| Operating income | 382,616 | 348,655 | 193,695 | 187,840 | 155,331 |
| Miscellaneous income (expense)[3] | 881 | 2,021 | 9,507 | 2,191 | (1,321) |
| Interest charges | 146,607 | 132,658 | 65,437 | 63,660 | 59,174 |
| Income before income taxes and cumulative effect of accounting change | 236,890 | 218,018 | 137,765 | 126,371 | 94,836 |
| Cumulative effect of accounting change, net income tax benefit | — | — | — | (7,773) | — |
| Income tax expense | 89,153 | 82,233 | 51,538 | 46,910 | 35,180 |
| Net income | $ 147,737 | $ 135,785 | $ 86,227 | $ 71,688 | $ 59,656 |
| Weighted average diluted shares outstanding | 81,390 | 79,012 | 54,416 | 46,496 | 41,250 |
| Diluted net income per share | $ 1.82 | $ 1.72 | $ 1.58 | $ 1.54 | $ 1.45 |
| Cash flows from operations | 311,449 | 386,944 | 270,734 | 49,541 | 297,395 |
| Cash dividends paid per share | $ 1.26 | $ 1.24 | $ 1.22 | $ 1.20 | $ 1.18 |
| Total utility throughput (MMcf) | 393,995 | 411,134 | 246,033 | 247,965 | 208,541 |
| Total natural gas marketing sales volumes (MMcf) | 283,962 | 238,097 | 222,572 | 225,961 | 204,027 |
| Total pipeline transportation volumes (MMcf) | 420,217 | 383,377 | — | — | — |
| **Financial Condition** | | | | | |
| Net property, plant and equipment[5] | $3,629,156 | $3,374,367 | $1,722,521 | $1,624,394 | $1,380,070 |
| Working capital[5] | (1,616) | 151,675 | 283,310 | 16,248 | (139,150) |
| Total assets[5][6] | 5,719,547 | 5,653,527 | 2,912,627 | 2,625,495 | 2,059,631 |
| Short-term debt, inclusive of current maturities of long-term debt | 385,602 | 148,073 | 5,908 | 127,940 | 167,771 |
| Capitalization: | | | | | |
| Shareholders' equity | 1,648,098 | 1,602,422 | 1,133,459 | 857,517 | 573,235 |
| Long-term debt (excluding current maturities) | 2,180,362 | 2,183,104 | 861,311 | 862,500 | 668,959 |
| Total capitalization | 3,828,460 | 3,785,526 | 1,994,770 | 1,720,017 | 1,242,194 |
| Capital expenditures | 425,324 | 333,183 | 190,285 | 159,439 | 132,252 |
| **Financial Ratios** | | | | | |
| Capitalization ratio[6] | 39.1% | 40.7% | 56.7% | 46.4% | 40.7% |
| Return on average shareholders' equity[7] | 8.9% | 9.0% | 9.1% | 9.9% | 9.9% |

See footnotes on the following page.

(1) Financial results for 2006 include a $22.9 million pre-tax loss for the impairment of the West Texas Division's irrigation assets.

(2) Financial results for 2005 include the results of the Mid-Tex Division and Atmos Pipeline — Texas Division from October 1, 2004, the date of acquisition.

(3) Financial results for 2004 include a $5.9 million pre-tax gain on the sale of our interest in U.S. Propane, L.P. and Heritage Propane Partners, L.P.

(4) Financial results for fiscal 2003 include the results of MVG from December 3, 2002, the date of acquisition.

(5) Beginning in 2004, we reclassified our regulatory cost of removal obligation from accumulated depreciation to a liability. The amounts presented above for property, plant and equipment, working capital and total assets reflect this reclassification for all periods presented. These reclassifications did not impact our financial position, results of operations or cash flows as of and for the years ended September 30, 2003 and 2002.

(6) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization and short-term debt, inclusive of current maturities of long-term debt. Beginning in 2004 we reclassified our original issue discount costs from deferred charges and other assets to long-term debt. This reclassification did not materially impact our capitalization or our capitalization ratio as of September 30, 2003 and 2002.

(7) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

The following table presents a condensed income statement by segment for the year ended September 30, 2006.

| | Year Ended September 30, 2006 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | | | (In thousands) | | | |
| Operating revenues from external parties | $3,649,851 | $2,418,856 | $ 81,857 | $1,799 | $ — | $6,152,363 |
| Intersegment revenues | 740 | 737,668 | 78,710 | 4,099 | (821,217) | — |
| | 3,650,591 | 3,156,524 | 160,567 | 5,898 | (821,217) | 6,152,363 |
| Purchased gas cost | 2,725,534 | 3,025,897 | 838 | — | (816,476) | 4,935,793 |
| Gross profit | 925,057 | 130,627 | 159,729 | 5,898 | (4,741) | 1,216,570 |
| Operating expenses | 723,163 | 28,392 | 81,871 | 5,506 | (4,978) | 833,954 |
| Operating income | 201,894 | 102,235 | 77,858 | 392 | 237 | 382,616 |
| Miscellaneous income | 9,506 | 2,598 | 2,554 | 4,151 | (17,928) | 881 |
| Interest charges | 126,489 | 8,510 | 25,331 | 3,968 | (17,691) | 146,607 |
| Income before income taxes | 84,911 | 96,323 | 55,081 | 575 | — | 236,890 |
| Income tax expense | 31,909 | 37,757 | 19,457 | 30 | — | 89,153 |
| Net income | $ 53,002 | $ 58,566 | $ 35,624 | $ 545 | $ — | $ 147,737 |
| Capital expenditures | $ 307,742 | $ 909 | $116,673 | $ — | $ — | $ 425,324 |

**ITEM 7.** ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

## INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Our performance in the future will primarily depend on the results of our utility and nonutility operations. Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

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

The statements contained in this Annual Report on Form 10-K 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: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business, the inherent hazards and risks involved in operating our distribution business, and other risks and uncertainties discussed herein, especially in Item 1A above, 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

In fiscal 2006, we earned $147.7 million in net income or $1.82 per diluted share, compared with net income of $135.8 million, or $1.72 per diluted share in fiscal 2005. The nine percent year-over-year increase in net income was primarily attributable strong financial results in our natural gas marketing segment as it was able to capture higher margins in a volatile natural gas market and favorable unrealized mark-to-market gains. Additionally, pipeline and storage net income increased 16 percent compared with the prior year. These positive results helped overcome the adverse effects on our utility segment of weather (adjusted for WNA) that was 13 percent warmer than normal, the adverse effect of Hurricane Katrina on our Louisiana Division and a non-recurring, noncash charge to impair certain assets. Our utility operations contributed $53.0 million ($0.65 per diluted share) or 36 percent to fiscal 2006 results. Our nonutility operations, comprised of our natural gas marketing, pipeline and storage and other nonutility segments, contributed $94.7 million ($1.17 per diluted share) or 64 percent to fiscal 2006 results. Key financial and other events for fiscal 2006 include the following:

- Our utility segment net income decreased $28.1 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. The decrease primarily resulted from the impact of weather, as adjusted for jurisdictions with weather-normalized rates, that was two percent warmer than the prior-year period and 13 percent warmer than normal, coupled with higher operating expenses. Utility segment results also reflect a $14.6 million net of tax charge associated with the impairment of the West Texas Division's irrigation assets.

- During fiscal 2006, our Louisiana and Mid-Tex divisions received WNA in their rate designs that will go into effect in fiscal 2007. After receiving WNA in these two jurisdictions, we will have weather protection for over 90 percent of our residential and commercial meters for the 2006-2007 winter heating season.

- Our natural gas marketing segment net income increased $35.2 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. The increase in natural gas marketing net income primarily reflects an increase in our unrealized margin of $43.2 million and increased realized margins due to our ability to capture higher margins in a volatile natural gas market. These increases were partially offset by a $7.4 million increase in operating expenses and increased interest charges resulting from increased short-term borrowings to fund working capital needs.

- Our pipeline and storage segment net income increased $5.0 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. Increased gross profit margin resulting from higher transportation and related services margins coupled with increased throughput on our Atmos Pipeline-Texas system and Atmos Pipeline & Storage, LLC's ability to capture more favorable arbitrage spreads in its asset management contracts were partially offset by higher operating expenses.

- Our capitalization ratio at September 30, 2006 was 60.9 percent compared with 59.3 percent at September 30, 2005 reflecting the impact of increased short-term debt borrowings to fund working capital needs partially offset by current-year net income.

- For the year ended September 30, 2006, we generated $311.4 million in operating cash flow compared with $386.9 million for the year ended September 30, 2005, reflecting the adverse impact of high natural gas costs on our working capital.

- Capital expenditures increased to $425.3 million from $333.2 million primarily reflecting increased capital spending for various pipeline expansion projects in our Atmos Pipeline — Texas Division.

Our financial performance is discussed in greater detail below in Results of Operations.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

*Regulation* — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our regulated utility operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in their financial statements. We record regulatory assets for costs that have been deferred for which 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. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized because they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our utility operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

*Revenue recognition* — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulators and are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues.

*Allowance for doubtful accounts* — For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

*Derivatives and hedging activities* — In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities.* Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, the maturity and settlement of contracts and newly originated transactions. However, because the costs of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related costs are recovered through our rates.

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

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

Under SFAS 133, natural gas inventory is designated as the hedged item in a fair-value hedge by AEM and Atmos Pipeline and Storage LLC. This inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Effective October 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact on our financial position on the date of adoption. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedges (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. We continually manage our positions and seek to optimize value as market conditions and other circumstances change. We elect to exclude the differential between the spot price used to value our physical inventory and the forward price used to value the financial hedges designated against our physical inventory for purposes of assessing the effectiveness of these fair-value hedges.

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

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

Additionally, we utilize 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. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue in our natural gas marketing segment.

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. This realized loss is being recognized as a component of interest expense over the life of the related financing arrangements.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

*Impairment assessments* — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. We currently have no indefinite-lived intangible assets. We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. We have determined our reporting units to be each of our utility divisions and wholly-owned subsidiaries. Goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill.

The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We periodically evaluate whether events or circumstances have occurred that indicate that our intangible assets subject to amortization and other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

*Pension and other postretirement plans* — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan cost over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension cost ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement cost by approximately $1.1 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement cost by approximately $0.8 million.

## RESULTS OF OPERATIONS

The following table presents our financial highlights for the three fiscal years ended September 30, 2006:

| | For the Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands, unless otherwise noted) | | |
| Operating revenues | $6,152,363 | $4,961,873 | $2,920,037 |
| Gross profit | 1,216,570 | 1,117,637 | 562,191 |
| Operating expenses | 833,954 | 768,982 | 368,496 |
| Operating income | 382,616 | 348,655 | 193,695 |
| Miscellaneous income | 881 | 2,021 | 9,507 |
| Interest charges | 146,607 | 132,658 | 65,437 |
| Income before income taxes | 236,890 | 218,018 | 137,765 |
| Income tax expense | 89,153 | 82,233 | 51,538 |
| Net income | $ 147,737 | $ 135,785 | $ 86,227 |
| Utility sales volumes — MMcf | 272,033 | 296,283 | 173,219 |
| Utility transportation volumes — MMcf | 121,962 | 114,851 | 72,814 |
| Total utility throughput — MMcf | 393,995 | 411,134 | 246,033 |
| Natural gas marketing sales volumes — MMcf | 283,962 | 238,097 | 222,572 |
| Pipeline transportation volumes — MMcf | 420,217 | 383,377 | — |
| Heating Degree Days [1] | | | |
| Actual (weighted average) | 2,527 | 2,587 | 3,271 |
| Percent of normal | 87% | 89% | 96% |
| Consolidated utility average transportation revenue per Mcf | $ 0.50 | $ 0.51 | $ 0.42 |
| Consolidated utility average cost of gas per Mcf sold | $ 10.02 | $ 7.41 | $ 6.55 |

[1] Adjusted for service areas that have weather normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

The following table shows our operating income by utility division and by segment for the three fiscal years ended September 30, 2006. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

| | 2006 | | 2005 | | 2004 | |
|---|---|---|---|---|---|---|
| | Operating Income | Heating Degree Days Percent of Normal[(1)] | Operating Income | Heating Degree Days Percent of Normal[(1)] | Operating Income | Heating Degree Days Percent of Normal[(1)] |
| | (In thousands, except degree day information) | | | | | |
| Colorado-Kansas | $ 22,524 | 99% | $ 25,157 | 99% | $ 20,876 | 99% |
| Kentucky | 14,338 | 100% | 18,657 | 98% | 22,738 | 98% |
| Louisiana | 27,772 | 78% | 24,819 | 78% | 40,762 | 93% |
| Mid-States | 35,555 | 95% | 35,687 | 93% | 38,778 | 95% |
| Mid-Tex | 71,703 | 72% | 84,965 | 80% | — | — |
| Mississippi | 23,276 | 102% | 19,045 | 96% | 18,709 | 101% |
| West Texas | 2,215 | 100% | 27,520 | 99% | 22,090 | 90% |
| Other | 4,511 | — | 515 | — | (4,063) | — |
| Utility segment | 201,894 | 87% | 236,365 | 89% | 159,890 | 96% |
| Natural gas marketing segment | 102,235 | — | 40,985 | — | 27,726 | — |
| Pipeline and storage segment | 77,858 | — | 70,286 | — | 5,293 | — |
| Other nonutility segment | 629 | — | 1,019 | — | 786 | — |
| Consolidated operating income | $382,616 | 87% | $348,655 | 89% | $193,695 | 96% |

(1) Adjusted for service areas that have weather-normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

**Year ended September 30, 2006 compared with year ended September 30, 2005**

***Utility segment***

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, during fiscal 2006, our utility segment contributed approximately 36 percent of our consolidated net income primarily due to the adverse effect of significantly warmer than normal weather, the adverse effect of Hurricane Katrina and a non-recurring, noncash charge to recognize the impairment of our irrigation assets. The primary factors that impact the results of our utility operations are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas sales to residential, commercial and public-authority customers are affected by winter heating season requirements. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations. Utility sales to industrial customers are much less weather sensitive.

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

The effects of weather that is above or below normal are substantially offset through weather normalization adjustments in most of our service areas. WNA allows us to increase the base rate portion of customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal. Accordingly, in our WNA service areas, our gross profit margin should be based substantially on the amount of gross profit that would result from normal weather, despite actual weather conditions that may be either warmer or colder than normal.

During fiscal 2006, we received WNA in our two most weather sensitive jurisdictions: the Louisiana and Mid-Tex divisions. With the addition of WNA in these two jurisdictions, we will have weather protection for over 90 percent of our residential and commercial meters for the 2006-2007 winter heating season. Prior to these decisions, there was limited weather protection in these jurisdictions. The Louisiana Division had previously benefited from a higher base customer charge. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal. In May 2006, the LPSC approved a settlement that provided for a modified WNA which provides a partial decoupling mechanism to stabilize this jurisdiction's margins. The approved WNA will cover a period from December to March.

Prior to October 1, 2006, the Mid-Tex Division, which is our largest utility division and contains almost 50 percent of our approximately 3.2 million distribution customers, had benefited from a rate structure that combined a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provided for the recovery of a significant portion of our fixed costs for such operations under average weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In July 2006, in connection with the Mid-Tex Division rate proceeding the RRC approved an interim and a permanent WNA effective October 1, 2006 for the Mid-Tex Division. The WNA covers the period from October through May. The interim WNA is based on 30 years of weather history, and the permanent WNA will be modified or adjusted to conform to the rate design that the RRC ultimately approves in the rate proceeding, which proceeding is described in greater detail under Recent Ratemaking Activity.

In the pending rate proceeding before the RRC, we are seeking for our Mid-Tex Division additional annual revenues of approximately $60 million and several rate design changes including revenue stabilization and recovery of the gas cost component of bad debt expense. While the outcome of the Mid-Tex Division's pending rate proceeding before the RRC cannot be predicted with certainty, we believe that we have adequately demonstrated to the RRC that the Mid-Tex Division is entitled to receive an increase in annual revenues and that the remaining rate design changes should be implemented. However, if the RRC were to deny an increase in the Mid-Tex Division's rates or not allow new rate design changes the Mid-Tex Division has requested, our business, financial condition and results of operations could be adversely affected in the future.

*Operating income*

Utility gross profit increased to $925.1 million for the year ended September 30, 2006 from $907.4 million for the year ended September 30, 2005. Total throughput for our utility business was 394.0 Bcf during the current year compared to 411.1 Bcf in the prior year.

The increase in utility gross profit, despite lower throughput, primarily reflects higher franchise fees and state gross receipts taxes, which are paid by utility customers and have no permanent effect on net income. Additionally, margins increased approximately $14.0 million due to rate increases received from our fiscal 2005 and fiscal 2004 GRIP filings and the recognition of $6.2 million that had been previously deferred in Louisiana following the LPSC's ratification of our agreement in May 2006. These increases were partially offset by approximately $22.9 million due to the impact of significantly warmer than normal weather, particularly in our Mid-Tex and Louisiana divisions. For the year ended September 30, 2006, weather was

13 percent warmer than normal, as adjusted for jurisdictions with weather-normalized operations and two percent warmer than the prior year. In the Mid-Tex and Louisiana Divisions, which did not have weather-normalized rates during the 2005-2006 winter heating season, weather was 28 percent and 22 percent warmer than normal.

Additionally, utility gross profit decreased approximately $2.9 million compared with the prior year in the Louisiana Division due to the impact of Hurricane Katrina. Service has been restored in some areas affected by the storm; however, it is not likely that service will be restored to all of the affected service areas. As more fully described under Recent Ratemaking Activity, we implemented new rates in September 2006 that reflect the impact of Hurricane Katrina.

Operating expenses increased to $723.2 million for the year ended September 30, 2006 from $671.0 million for the year ended September 30, 2005. The increase reflects a $13.3 million increase in taxes, primarily related to franchise fees and state gross receipts taxes, both of which are calculated as a percentage of revenue, and are paid by our customers as a component of their monthly bills. Although these amounts are included as a component of revenue in accordance with our tariffs, timing differences between when these amounts are billed to our customers and when we recognize the associated expense may affect net income favorably or unfavorably on a temporary basis. However, there is no permanent effect on net income.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $7.8 million primarily due to higher employee costs associated with increased headcount to fill positions that were previously outsourced to a third party, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Increased line locate, telecommunication and facilities costs also contributed to the overall increase. These increases were partially offset by a reduction in third-party costs for outsourced administrative and meter reading functions that were in-sourced during fiscal 2006. Operation and maintenance expense for the year ended September 30, 2006 was also favorably impacted by the absence of $2.1 million of merger and integration cost amortization associated with the merger of United Cities Gas Company in July 1997, as these costs were fully amortized by December 2004.

The provision for doubtful accounts increased $3.1 million to $20.6 million for the year ended September 30, 2006, compared with $17.5 million in the prior year. The increase was primarily attributable to increased collection risk associated with higher natural gas prices. In the utility segment, the average cost of natural gas for the year ended September 30, 2006 was $10.02 per Mcf, compared with $7.41 per Mcf for the year ended September 30, 2005.

Additionally, during the first quarter of fiscal 2006, the MPSC, in connection with the modification of our rate design described in Recent Ratemaking Activity, decided to allow the recovery of $2.8 million in deferred costs, which it had originally disallowed in its September 2004 decision. This charge was originally recorded in fiscal 2004. This ruling decreased our depreciation expense during the year ended September 30, 2006. This decrease was offset by increased depreciation expense associated with the placement of various capital projects into service during the fiscal year.

Operating expenses were also impacted by $22.9 million noncash charge to impair our West Texas Division's irrigation assets. During the fiscal 2006 fourth quarter, we determined that, as a result of declining irrigation sales primarily associated with our agricultural customers' shift from gas-powered pumps to electric pumps, the West Texas Division's irrigation assets would not be able to generate sufficient future cash flows from operations to recover the net investment in these assets. Therefore, the entire net book value was written off. We will continue to operate these assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2006 decreased to $201.9 million from $236.4 million for the year ended September 30, 2005.

*Miscellaneous income*

Miscellaneous income for the year ended September 30, 2006 was $9.5 million compared to miscellaneous income of $6.8 million for the year ended September 30, 2005. This increase was primarily attributable to increased interest income on intercompany borrowings to our natural gas marketing segment to fund its working capital needs. This increase was partially offset by a $3.3 million charge recorded during the fiscal 2006 second quarter associated with an adverse ruling in Tennessee related to the calculation of a performance-based rate mechanism associated with gas purchases.

*Interest charges*

Interest charges allocated to the utility segment for the year ended September 30, 2006 increased to $126.5 million from $112.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding short-term debt balances to fund natural gas purchases at significantly higher prices coupled with an approximate 200 basis point increase in the interest rate on our $300 million unsecured floating rate Senior Notes due 2007 due to an increase in the three-month LIBOR rate. These increases were partially offset by $4.8 million of interest savings arising from the early payoff of $72.5 million of our First Mortgage Bonds in June 2005.

***Natural gas marketing segment***

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

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivative contracts, we seek to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

*Operating income*

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

Our natural gas marketing segment's gross profit margin was comprised of the following for the year ended September 30, 2006 and 2005:

| | Year Ended September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands, except physical position) | |
| Storage Activities | | |
| Realized margin | $ 26,225 | $ 28,008 |
| Unrealized margin | (1,293) | (14,007) |
| Total Storage Activities | 24,932 | 14,001 |
| Marketing Activities | | |
| Realized margin | 87,236 | 59,971 |
| Unrealized margin | 18,459 | (11,999) |
| Total Marketing Activities | 105,695 | 47,972 |
| Gross profit | $130,627 | $ 61,973 |
| Net physical position (Bcf) | 14.5 | 6.9 |

Our natural gas marketing segment's gross profit margin was $130.6 million for the year ended September 30, 2006 compared to gross profit of $62.0 million for the year ended September 30, 2005. Gross profit margin from our natural gas marketing segment for the year ended September 30, 2006 included an unrealized gain of $17.2 million compared with an unrealized loss of $26.0 million in the prior year. Natural gas marketing sales volumes were 336.5 Bcf during the year ended September 30, 2006 compared with 273.2 Bcf for the prior year. Excluding intersegment sales volumes, natural gas marketing sales volumes were 284.0 Bcf during the current year compared with 238.1 Bcf in the prior year. The increase in consolidated natural gas marketing sales volumes was primarily due to focusing our marketing efforts on higher margin opportunities partially offset by warmer-than-normal weather across our market areas.

Our storage activities generated $24.9 million in gross profit margin for the year ended September 30, 2006 compared to $14.0 million for the year ended September 30, 2005. Lower realized margins in our storage operations were primarily due to the realization of less favorable arbitrage spreads compared with the prior year coupled with increased storage fees. These decreases were partially offset by a decrease in the unrealized loss associated with these operations due to a favorable movement during the year ended September 30, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory and our fixed-price forward contracts. These decreases were also favorably impacted by positive basis ineffectiveness resulting from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the derivative instruments designated as a fair value hedge. These results were magnified by a 7.6 Bcf increase in our net physical position at September 30, 2006 compared to the prior year. We continually seek opportunities to increase the amount of our storage capacity. To the extent we obtain and utilize new capacity and experience price volatility, the amount of our unrealized storage contribution could increase in future periods.

Our marketing activities generated $105.7 million in gross profit margin for the year ended September 30, 2006 compared with $48.0 million for the year ended September 30, 2005. This increase reflects increased realized margins coupled with a favorable unrealized margin variance compared with the prior year. The increase in our realized marketing operations was primarily attributable to successfully capturing increased margins in certain market areas that experienced higher market volatility. The favorable unrealized margin variance was primarily due to favorable movement during the year ended September 30, 2006 in the forward natural gas prices associated with financial derivatives used in these activities and positive basis ineffectiveness on those financial derivatives.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $28.4 million for the year ended September 30, 2006 from $21.0 million for the year ended September 30, 2005. The increase in operating expense primarily was attributable to an increase in personnel costs due to increased headcount and an increase in regulatory compliance costs.

The improved gross profit margin partially offset by higher operating expenses resulted in an increase in our natural gas marketing segment operating income to $102.2 million for the year ended September 30, 2006 compared with operating income of $41.0 million for the year ended September 30, 2005.

*Interest charges*

Interest charges allocated to the natural gas marketing segment for the year ended September 30, 2006 increased to $8.5 million from $3.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding debt balances to fund natural gas purchases at significantly higher prices.

***Pipeline and storage segment***

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS), which were previously included in our other nonutility segment. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for 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 inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations 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. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

*Operating income*

Gross profit margin for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees earned by APS. Our pipeline and storage segment's gross profit margin was comprised of the following components for the year ended September 30, 2006 and 2005:

| | Year Ended September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Mid-Tex transportation | $ 69,925 | $ 70,089 |
| Third party transportation | 58,490 | 55,376 |
| Asset management fees | 10,333 | 8,559 |
| Storage and park and lend services | 11,297 | 7,451 |
| Unrealized gains (losses) | 3,350 | (4,730) |
| Other | 6,334 | 9,733 |
| Gross profit | $159,729 | $146,478 |

Pipeline and storage gross profit increased to $159.7 million for the year ended September 30, 2006 from $146.5 million for the year ended September 30, 2005. Total pipeline transportation volumes were 591.0 Bcf during the year ended September 30, 2006 compared with 563.9 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 420.2 Bcf during the current year compared with 383.4 Bcf in the prior year.

The increase in gross profit was primarily attributable to increased third-party throughput and ancillary services, coupled with increased margins on APS' asset management contracts. Increased third-party throughput on Atmos Pipeline — Texas was primarily attributable to increases in the electric-generation market due to the warmer than normal temperatures during the summer of 2006, increased demand for through-system transportation services due to a widening of pricing differentials between the pipeline's hubs and the impact of Atmos Pipeline — Texas' North Side Loop and other compression projects that were placed into service in June 2006. Storage and parking and lending services on Atmos Pipeline — Texas also increased during fiscal 2006 as a result of the widening of pricing differentials between the pipeline's hubs, which increased the attractiveness of storing gas on the pipeline and our ability to obtain improved margins for these services. The increases on Atmos Pipeline — Texas' system were partially offset by a decrease in margins earned from intercompany transportation services to our Mid-Tex Division due to the significantly warmer than normal weather experienced during fiscal 2006. Additionally, these increases were partially offset by the absence of inventory sales of $3.0 million realized in the prior year.

Increases in APS' margins due to its ability to capture more favorable arbitrage spreads on its asset management contracts also contributed to this segment's improved gross profit margin. These improved margins reflect an unrealized component as APS hedges its risk associated with these contracts. During fiscal 2006, favorable movements in the forward natural gas prices used to value the financial hedges designated against the physical inventory underlying these contracts resulted in an unrealized gain compared with an unrealized loss in the prior year.

Operating expenses increased to $81.9 million for the year ended September 30, 2006 from $76.2 million for the year ended September 30, 2005 due to higher employee benefit costs associated with the increase in headcount, increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs, higher facilities costs and higher pipeline integrity costs.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the year ended September 30, 2006 increased to $77.9 million from $70.3 million for the year ended September 30, 2005.

### *Other nonutility segment*

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

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the year ended September 30, 2006 compared with the prior year.

## Year ended September 30, 2005 compared with year ended September 30, 2004

### *Utility segment*

*Operating income*

Utility gross profit increased to $907.4 million for the year ended September 30, 2005 from $503.1 million for the year ended September 30, 2004. Total throughput for our utility business was 411.1 Bcf during the current year compared to 246.0 Bcf in the prior year.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of the Mid-Tex Division resulting in an increase in utility gross profit margin and total throughput of $398.2 million and 174.3 Bcf. The $6.1 million increase in the gross profit generated from our other utility operations primarily reflects rate increases in our Mississippi and West Texas divisions that were absent in the prior year coupled with the recognition of a $1.9 million refund to our customers in our Colorado service area in the prior year. Offsetting these increases was a $3.9 million reduction in gross profit in our Louisiana Division due to the impact of Hurricane Katrina. Gross profit margins, particularly in Louisiana, were also adversely impacted by weather (as adjusted for jurisdictions with weather-normalized operations) that was five percent warmer than normal and one percent warmer than the prior year period. Additionally, gross profit margin was adversely impacted by the lack of cold weather in patterns sufficient to encourage customers to increase their heat load consumption and lower irrigation throughput in our West Texas and Colorado-Kansas Divisions.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $671.0 million for the year ended September 30, 2005 from $343.2 million for the year ended September 30, 2004 primarily as a result of the addition of the Mid-Tex Division. Excluding the impact of the Mid-Tex Division, operating expenses for our other utility operations increased $14.5 million primarily due to $2.3 million associated with the effects of Hurricane Katrina, a $7.7 million increase in taxes, other than income, a $2.4 million increase in operation and maintenance expense, including the provision for doubtful accounts, and a $2.1 million increase in depreciation and amortization. Included in taxes other than income taxes are franchise and state gross receipts taxes which are paid by our customers as a component of their monthly bills. Although these amounts are offset in revenues through customer billings, timing differences between when the expense is incurred and is recovered may impact our net income on a temporary basis. However, there is no permanent effect on net income.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2005 increased to $236.4 million from $159.9 million for the year ended September 30, 2004.

*Miscellaneous income*

Miscellaneous income increased to $6.8 million for the year ended September 30, 2005 from $5.8 million for the year ended September 30, 2004. The increase was attributable to an increase in interest income earned on higher cash balances during the current year compared with the prior year partially offset by the recognition of a $0.8 million gain on the sale of a building during the year ended September 30, 2004.

*Interest charges*

Interest charges allocated to the utility segment for the year ended September 30, 2005 increased to $112.4 million from $65.4 million for the year ended September 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Mid-Tex Division in October 2004. On June 30, 2005, we repaid $72.5 million in principal on five series of our First Mortgage Bonds prior to their scheduled maturities. The early repayment of these bonds resulted in savings of $1.3 million in interest expense in fiscal 2005.

***Natural gas marketing segment***

*Operating income*

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

| | Year Ended September 30 | |
|---|---|---|
| | 2005 | 2004 |
| | (In thousands, except physical position) | |
| Storage Activities | | |
| Realized margin | $ 28,008 | $ (1,900) |
| Unrealized margin | (14,007) | 357 |
| Total Storage Activities | 14,001 | (1,543) |
| Marketing Activities | | |
| Realized margin | 59,971 | 51,347 |
| Unrealized margin | (11,999) | (3,173) |
| Total Marketing Activities | 47,972 | 48,174 |
| Gross profit | $ 61,973 | $46,631 |
| Net physical position (Bcf) | 6.9 | 5.4 |

Our natural gas marketing segment's gross profit margin was $62.0 million for the year ended September 30, 2005 compared to gross profit of $46.6 million for the year ended September 30, 2004. Gross profit margin from our natural gas marketing segment for the year ended September 30, 2005 included an unrealized loss of $26.0 million compared with an unrealized loss of $2.8 million in the prior year. Natural gas marketing sales volumes were 273.2 Bcf during the year ended September 30, 2005 compared with 265.1 Bcf for the prior year. Excluding intersegment sales volumes, natural gas marketing sales volumes were 238.1 Bcf during the current year compared with 222.6 Bcf in the prior year. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies into new market areas.

The contribution to gross profit from our storage activities was a gain of $14.0 million for the year ended September 30, 2005 compared to a loss of $1.5 million for the year ended September 30, 2004. The $15.5 million improvement primarily was attributable to a $29.9 million increase in the realized storage contribution for the year ended September 30, 2005 compared to the prior year due to more favorable arbitrage spread opportunities during the current year, partially offset by increased storage fees associated with 9.0 Bcf of newly contracted storage capacity during the third quarter of fiscal 2005. Annual demand charges for this new storage approximate $7.6 million. We may further increase the amount of our storage capacity in the future; therefore, the impact of price volatility on our unrealized storage contribution could become more significant in future periods.

A $14.4 million decrease in the unrealized storage contribution resulted from an unfavorable movement during the year ended September 30, 2005 in the forward indices used to value the storage financial instruments combined with greater physical natural gas storage quantities at September 30, 2005 compared to the prior year also.

Our marketing activities contributed $48.0 million to our gross profit for the year ended September 30, 2005 compared to $48.2 million for the year ended September 30, 2004. The decrease in the marketing contribution primarily was attributable to $12.0 million of unrealized marked-to-market losses associated with basis swaps that were put in place to capture margins in certain volatile market areas. The increase in unrealized marked-to-market losses was partially offset by an increase in our realized marketing margins due to focusing our marketing efforts on higher margin customers and successfully entering into new market areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $21.0 million for the year ended September 30, 2005 from $18.9 million for the year ended September 30, 2004. The increase in operating expense was attributable primarily to an increase in labor costs due to increased headcount and an increase in regulatory compliance costs.

The increase in gross profit margin, combined with higher operating expenses, resulted in an increase in our natural gas marketing segment operating income to $41.0 million for the year ended September 30, 2005 compared with operating income of $27.7 million for the year ended September 30, 2004.

***Pipeline and storage segment***

*Operating income*

Pipeline and storage gross profit increased to $146.5 million for the year ended September 30, 2005 from $10.4 million for the year ended September 30, 2004. Total pipeline transportation volumes were 563.9 Bcf during the year ended September 30, 2005 compared with 9.4 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 383.4 Bcf during the current year.

The increase in pipeline and storage gross profit margin primarily reflects the impact of the acquisition of the Atmos Pipeline — Texas Division resulting in an increase in pipeline and storage gross profit margin and total transportation volumes of $138.1 million and 375.6 Bcf. Also contributing to Atmos Pipeline — Texas Division's results were higher transportation and related services margin due to significant basis differentials at its three major Texas hubs. The $2.0 million decrease in the gross profit generated by APS primarily reflects a decrease in asset management fees received during fiscal 2005.

Operating expenses increased to $76.2 million for the year ended September 30, 2005 from $5.1 million for the year ended September 30, 2004 due to the addition of $72.2 million in operating expenses associated with the Atmos Pipeline — Texas Division. As the Atmos Pipeline — Texas Division is a regulated entity, franchise and state gross receipts taxes are paid by our customers; thus, these amounts are offset in revenues through customer billings and have no permanent effect on net income. Included in operating expense was $8.9 million associated with taxes other than income taxes, of which $8.3 million was associated with our Atmos Pipeline — Texas Division.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the year ended September 30, 2005 increased to $70.3 million from $5.3 million for the year ended September 30, 2004.

*Interest charges*

Interest charges allocated to this segment for the year ended September 30, 2005 increased to $24.6 million from $1.1 million for the year ended September 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Atmos Pipeline — Texas Division in October 2004.

### *Other nonutility segment*

Operating income for our other nonutility segment primarily reflects the leasing income associated with two sales-type lease transactions completed in fiscal 2001 and 2002. The increase in operating income during the year ended September 30, 2005 reflects the absence of a one-time charge of $0.4 million associated with the wind-down of a noncore business during fiscal 2004.

Miscellaneous income for the year ended September 30, 2005 was $2.6 million compared with $8.3 million for the year ended September 30, 2004. The $5.7 million decrease was attributable primarily to the recognition of a $5.9 million pretax gain on the sale of all remaining limited partnership interests in Heritage Propane Partners, L.P. during fiscal 2004.

## LIQUIDITY AND CAPITAL RESOURCES

Our working capital and liquidity for capital expenditure and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program and funds raised from the public debt and equity capital markets. We believe that these sources of funds will provide the necessary working capital and liquidity for capital expenditures and other cash needs for fiscal 2007. These facilities are described in greater detail below and in Note 6 to the consolidated financial statements.

### Capitalization

The following presents our capitalization as of September 30, 2006 and 2005:

| | September 30 | | | |
|---|---|---|---|---|
| | 2006 | | 2005 | |
| | (In thousands, except percentages) | | | |
| Short-term debt | $ 382,416 | 9.1% | $ 144,809 | 3.7% |
| Long-term debt | 2,183,548 | 51.8% | 2,186,368 | 55.6% |
| Shareholders' equity | 1,648,098 | 39.1% | 1,602,422 | 40.7% |
| Total capitalization, including short-term debt | $4,214,062 | 100.0% | $3,933,599 | 100.0% |

Total debt as a percentage of total capitalization, including short-term debt, was 60.9 percent and 59.3 percent at September 30, 2006 and 2005. The increase in the debt to capitalization ratio was primarily attributable to an increase in our short-term debt borrowings to fund our working capital needs partially offset by current-year net income. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. Within three to five years, we intend to reduce our capitalization ratio to a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

### Cash Flows

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

#### *Cash flows from operating activities*

Year-over-year changes in our operating cash flows are primarily attributable to working capital changes within our utility segment resulting from the impact of weather, the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the year ended September 30, 2006, we generated operating cash flow of $311.4 million compared with $386.9 million in fiscal 2005 and $270.7 million in fiscal 2004. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

*Year ended September 30, 2006*

Fiscal 2006 operating cash flows reflect the adverse impact of significantly higher natural gas prices. Year-over-year, unfavorable timing of payments for accounts payable and other accrued liabilities reduced operating cash flow by $523.0 million. Partially offsetting these outflows were higher customer collections ($245.1 million) and reduced payments for natural gas inventories ($102.1 million). Additionally, favorable movements in the market indices used to value our natural gas marketing segment risk management assets and liabilities reduced the amount that we were required to deposit in a margin account and therefore favorably affected operating cash flow by $126.3 million.

*Year ended September 30, 2005*

Fiscal 2005 operating cash flows reflect the effects of a $49.6 million increase in net income and effective working capital management partially offset by higher natural gas prices. Working capital management efforts, which affected the timing of payments for accounts payable and other accrued liabilities, favorably affected operating cash flow by $354.1 million. However, these efforts were partially offset by reduced cash flow generated from accounts receivable changes by $168.9 million, primarily attributable to higher natural gas prices, and an increase in our natural gas inventories attributable to a 13 percent year-over-year increase in natural gas prices coupled with increased natural gas inventory levels, which reduced operating cash flow by $81.8 million. Operating cash flow was also adversely impacted by unfavorable movements in the indices used to value our natural gas marketing segment risk management assets and liabilities, which resulted in a net liability for the segment. Accordingly, under the terms of the associated derivative contracts, we were required to deposit $81.0 million into a margin account.

*Year ended September 30, 2004*

Fiscal 2004 operating cash flows were favorably impacted by several items. Improved customer collections during fiscal 2004, compared with the prior year, resulted in a $62.2 million increase in operating cash flow. Further, cash used for natural gas inventories decreased by $33.8 million compared with the prior year. The decrease was attributable to lower injections of natural gas into storage, partially offset by higher prices. The reduction in the lag between the time period when we purchase our natural gas and the period in which we can include this cost in our gas rates improved operating cash flow by $65.7 million. Changes in cash held on deposit in margin accounts resulted in an increase in operating cash flow of $25.6 million. This account represents deposits recorded to collateralize certain of our financial derivatives purchased in support of our natural gas marketing activities. The favorable change was attributable to the fact that the fair value of financial instruments held by AEM represented a net asset position at September 30, 2004, which eliminated the need to place cash in margin accounts. Finally, other working capital and other changes improved operating cash flow by $33.9 million. These changes primarily related to various increases in deferred credits and other liabilities, other current liabilities and income taxes payable partially offset by lower deferred income tax expense as compared with the prior year.

***Cash flows from investing activities***

During the last three years, a substantial portion of our cash resources was used to fund acquisitions and growth projects, our ongoing construction program and improvements to information systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, to expand our natural gas distribution services into new markets, to enhance the integrity of our pipelines and, more recently, to 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 return on our investment timely. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the year ended September 30, 2006, we incurred $425.3 million for capital expenditures compared with $333.2 million for the year ended September 30, 2005 and $190.3 million for the year ended

September 30, 2004. The increase in capital expenditures in fiscal 2006 primarily reflects increased spending associated with our Dallas/Fort Worth Metroplex North Side Loop project and other pipeline expansion projects in our Atmos Pipeline — Texas Division, which were completed during the fiscal 2006 third quarter. Increased capital spending in our Mid-Tex Division for various projects also contributed to the increase in our capital expenditures.

Our cash used for investing activities for the year ended September 30, 2005 reflects the $1.9 billion cash paid for the TXU Gas acquisition including related transaction costs and expenses. Cash flow from investing activities for the year ended September 30, 2004 reflects the receipt of $27.9 million from the sale of our limited and general partnership interests in USP and Heritage Propane Partners, L.P. and from the sale of a building.

***Cash flows from financing activities***

For the year ended September 30, 2006, our financing activities provided $155.3 million in cash compared with $1.7 billion and $80.4 million provided for the years ended September 30, 2005 and 2004. Our significant financing activities for the years ended September 30, 2006, 2005 and 2004 are summarized as follows:

- In October 2004, we sold 16.1 million shares of common stock, including the underwriters' exercise of their overallotment option of 2.1 million shares, under a shelf registration statement declared effective in September 2004, generating net proceeds of $382 million. Additionally, we issued $1.39 billion of senior unsecured debt under our shelf registration statement with an initial weighted average effective interest rate on these notes of 4.76 percent. The net proceeds from these issuances, combined with the net proceeds from our July 2004 common stock offering were used to finance the acquisition of our Mid-Tex and Atmos Pipeline — Texas divisions and settle Treasury lock agreements, into which we entered to fix the Treasury yield component of the interest cost of financing associated with $875 million of the $1.39 billion long-term debt we issued in October 2004 to fund the acquisition.

- During the years ended September 30, 2006 and 2005, we increased our borrowings under our short-term facilities by $237.6 million and $144.8 million whereas during the year ended September 30, 2004, we repaid a net $118.6 million under our short-term facilities. Net borrowings under our short-term facilities during fiscal 2006 and 2005 reflect the impact of seasonal natural gas purchases and the effect of higher natural gas prices than in prior years.

- We repaid $3.3 million of long-term debt during the year ended September 30, 2006 compared with $103.4 million during the year ended September 30, 2005 and $9.7 million during the year ended September 30, 2004. Fiscal 2005 payments reflected the repayment of $72.5 million of our First Mortgage Bonds. In connection with this repayment we paid a $25.0 million make-whole premium in accordance with the terms of the agreements and accrued interest of approximately $1.0 million. In accordance with regulatory requirements, the premium has been deferred and will be recognized over the remaining original lives of the First Mortgage Bonds that were repaid. The early repayment of these bonds resulted in interest savings of $4.8 million and $1.3 million in fiscal 2006 and 2005.

- During the year ended September 30, 2006, we paid $102.3 million in cash dividends compared with dividend payments of $99.0 million and $66.7 million for the years ended September 30, 2005 and 2004. The increase in dividends paid over the prior year reflects an increase in the dividend rate from $1.24 per share during the year ended September 30, 2005 to $1.26 per share during the year ended September 30, 2006 combined with new share issuances under our various plans.

During the year ended September 30, 2006 we issued 0.9 million shares of common stock which generated net proceeds of $23.3 million. In addition, we granted 0.3 million shares of common stock under our 1998 Long-Term Incentive Plan to directors, officers and other participants in the plan. The following table shows the number of shares issued for the years ended September 30, 2006, 2005 and 2004:

| | For the Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Shares issued: | | | |
| Direct stock purchase plan | 387,833 | 450,212 | 556,856 |
| Retirement savings plan | 442,635 | 441,350 | 320,313 |
| 1998 Long-term incentive plan | 366,905 | 745,788 | 498,230 |
| Long-term stock plan for Mid-States Division | 300 | — | 6,000 |
| Outside directors stock-for-fee plan | 2,442 | 2,341 | 3,133 |
| October 2004 Offering | — | 16,100,000 | — |
| July 2004 Offering | — | — | 9,939,393 |
| Total shares issued | 1,200,115 | 17,739,691 | 11,323,925 |

### Shelf Registration

In December 2001, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC in January 2002. In July 2004, we sold 9.9 million shares of our common stock, including the underwriters' exercise of their overallotment option, which exhausted the remaining availability under this registration statement.

In August 2004, we filed a registration statement with the SEC to issue, from time to time, up to $2.2 billion in new common stock and/or debt, which became effective in September 2004. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option of 2.1 million shares, under this registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued $1.39 billion of senior unsecured debt under the registration statement. After issuing the debt and equity in October 2004, we had approximately $401.5 million of availability remaining under this registration statement. However, we are no longer allowed to issue securities under that registration statement by applicable state regulatory commissions since we are in the process of securing their approval to issue a total of $900 million in securities under a new shelf registration statement, including the remaining $401.5 million of capacity carried over from the currently effective registration statement. We intend to file this new registration statement with the SEC in the near future.

### Credit Facilities

As of September 30, 2006, we maintained three short-term committed credit facilities totaling $918 million. We also maintain one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital have increased substantially as a result of the significant increase in the price of natural gas.

In October 2005, our $600 million 364-day committed credit facility expired and was replaced with a $600 million three-year revolving credit facility. In addition, in November 2005, we entered into a new $300 million 364-day revolving credit facility with substantially the same terms as our $600 million credit facility.

In November 2006, we renewed our $300 million 364-day revolving credit facility and were in the process of replacing our three-year $600 million facility with a five-year $600 million revolving credit facility. Both facilities are being renewed with substantially the same terms as their predecessor facilities.

In April 2006, our $18 million committed unsecured credit facility was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, $3.1 million was outstanding under this facility.

As of September 30, 2006, the amount available to us under these credit facilities, net of outstanding letters of credit, was $609.0 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our increased working capital needs. These facilities are described in further detail in Note 6 to the consolidated financial statements.

In November 2005, AEM amended its uncommitted demand working capital credit facility to increase the amount of credit available from $250 million to a maximum of $580 million. In March 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 2007. At September 30, 2006, there were no borrowings outstanding under this facility.

**Credit Ratings**

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Services, Inc. (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

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

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

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

**Debt Covenants**

We were in compliance with all of our debt covenants as of September 30, 2006. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as both our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other triggering events.

Additional information concerning our debt covenants and how we complied with those covenants is included in Note 6 to the consolidated financial statements.

**Contractual Obligations and Commercial Commitments**

The following tables provide information about contractual obligations and commercial commitments at September 30, 2006.

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years |
| | | | (In thousands) | | |
| **Contractual Obligations** | | | | | |
| Long-term debt[1] | $2,186,878 | $ 3,186 | $305,865 | $ 762,762 | $1,115,065 |
| Short-term debt[1] | 382,416 | 382,416 | — | — | — |
| Interest charges[2] | 1,028,096 | 121,511 | 207,939 | 164,964 | 533,682 |
| Gas purchase commitments[3] | 708,217 | 560,461 | 110,793 | 17,035 | 19,928 |
| Capital lease obligations[4] | 2,777 | 433 | 673 | 477 | 1,194 |
| Operating leases[4] | 176,806 | 15,959 | 30,157 | 26,912 | 103,778 |
| Demand fees for contracted storage[5] | 17,989 | 8,832 | 7,257 | 1,900 | — |
| Demand fees for contracted transportation[6] | 27,818 | 4,269 | 5,944 | 5,788 | 11,817 |
| Derivative obligations[7] | 30,945 | 30,669 | 276 | — | — |
| Postretirement benefit plan contributions[8] | 145,198 | 11,408 | 21,584 | 26,141 | 86,065 |
| Total contractual obligations | $4,707,140 | $1,139,144 | $690,488 | $1,005,979 | $1,871,529 |

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

(2) Interest charges were calculated using the stated rate for each debt issuance, or in the case of floating rate debt, the rate that was in effect as of September 30, 2006.

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2006.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our natural gas marketing and other utility segments. Contractual demand fees for contracted storage for our utility segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(6) Represents third party contractual demand fees for transportation in our natural gas marketing segment.

(7) Represents liabilities for natural gas commodity derivative contracts that were valued as of September 30, 2006. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the derivative contracts are settled.

(8) Represents expected contributions to our postretirement benefit plans.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2006, AEM was committed to purchase 61.7 Bcf within one year, 51.2 Bcf between one to three years and 0.8 Bcf after three years under indexed contracts. AEM was committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $3.40 to $12.00 per Mcf.

With the exception of our Mid-Tex Division, our utility segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contract terms as of September 30, 2006 are reflected in the table above.

In May 2006, we announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky that will originate in Floyd County, Kentucky, and extend north approximately 60 miles to interconnect with the Tennessee Gas Pipeline in Carter County, Kentucky. Tennessee Gas Pipeline's interstate system delivers natural gas to the northeastern United States, including New York City and Boston. Referred to as the Straight Creek Project, the new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. More than a dozen other producers have signed memoranda of understanding to commit gas volumes to the new system and to enter into agreements on commercially reasonable terms.

As currently designed, the project is expected to cost between $75 million to $80 million. In October 2006, FERC issued a declaratory order finding that the Straight Creek Project will be exempt from FERC jurisdiction. Upon receiving all required regulatory approvals, construction is expected to begin in the first half of fiscal 2007, with operations expected to begin in fiscal 2008. Final terms of the joint venture are still being negotiated; however, we anticipate that we will have the ability to consolidate the joint venture.

**Risk Management Activities**

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

In our natural gas marketing segment, hedge ineffectiveness resulting from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments (referred to as basis ineffectiveness) for both fair value and cash flow hedges was an unrealized gain of approximately $35.5 million for the year ended September 30, 2006 and an unrealized loss of approximately $5.4 million and $1.1 million for the years ended September 30, 2005 and 2004. Actual hedge ineffectiveness resulting from the timing of settlement of physical contracts and the settlement of the derivative instruments (referred to as timing ineffectiveness) resulted in an unrealized gain of approximately $4.4 million and $0.5 million for the years ended September 30, 2006 and 2004 and an unrealized loss of approximately $2.2 million for the year ended September 30, 2005.

In our pipeline and storage segment, timing ineffectiveness resulted in an unrealized loss of approximately $4.7 million and less than $0.1 million for the years ended September 30, 2006 and 2004 and an unrealized gain of approximately $5.2 million for the year ended September 30, 2005.

Finally, during fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the consolidated financial statements.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following table shows the components of the change in fair value of our utility and natural gas marketing derivative contract activities for the year ended September 30, 2006 (in thousands):

| | Utility | Natural Gas Marketing |
|---|---|---|
| Fair value of contracts at September 30, 2005 | $ 93,310 | $(61,898) |
| Contracts realized/settled | 25,461 | 11,106 |
| Fair value of new contracts | (18,651) | — |
| Other changes in value | (127,329) | 65,795 |
| Fair value of contracts at September 30, 2006 | $ (27,209) | $ 15,003 |

The fair value of our utility and natural gas marketing derivative contracts at September 30, 2006, is segregated below by time period and fair value source.

| | Fair Value of Contracts at September 30, 2006 | | | | |
|---|---|---|---|---|---|
| | Maturity in Years | | | | |
| Source of Fair Value | Less Than 1 | 1-3 | 4-5 | Greater Than 5 | Total Fair Value |
| | (In thousands) | | | | |
| Prices actively quoted | $(17,421) | $7,122 | $— | $— | $(10,299) |
| Prices provided by other external sources | (440) | (936) | — | — | (1,376) |
| Prices based on models and other valuation methods | (255) | (276) | — | — | (531) |
| Total Fair Value | $(18,116) | $5,910 | $— | $— | $(12,206) |

### *Storage and Hedging Outlook*

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

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact to the Company on the date of adoption. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the gross profit that it captured and expects to collect through the purchase and sale of physical natural gas and the associated financial derivatives, which we refer to as the economic gross profit. The economic gross profit, combined with the effect of unrealized gains or losses recognized in the financial statements in prior periods, provides a measure of the gross profit that could occur in future periods if AEM's optimization efforts are fully successful. The following table presents AEM's economic gross profit and its potential gross profit for the last three fiscal years.

| Period Ending | Net Physical Position (Bcf) | Economic Gross Profit (In millions) | Associated Net Unrealized (Loss) (In millions) | Potential Gross Profit (In millions) |
|---|---|---|---|---|
| September 30, 2006 | 14.5 | $60.0 | $(16.0) | $76.0 |
| September 30, 2005 | 6.9 | $13.1 | $(14.8) | $27.9 |
| September 30, 2004 | 5.4 | $12.3 | $ (0.8) | $13.1 |

As of September 30, 2006, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $60.0 million. In addition, $16.0 million of net unrealized losses were recorded in the financial statements as of September 30, 2006. Therefore, the potential gross profit was $76.0 million. This potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot assure that the economic gross profit or the potential gross profit calculated as of September 30, 2006 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

## Pension and Postretirement Benefits Obligations

### *Net Periodic Pension and Postretirement Benefit Costs*

For the fiscal year ended September 30, 2006, our total net periodic pension and other benefits costs was $50.0 million, compared with $36.4 million and $26.1 million for the years ended September 30, 2005 and 2004. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The increase in total net periodic pension and other benefits cost during fiscal 2006 compared with the prior year primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2005. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2005 measurement date, these interest rates were declining, which resulted in a 125 basis point reduction in our discount rate to 5.0 percent. This reduction increased the present value of our plan liabilities and associated expenses. Additionally, we reduced the expected return on our pension plan assets by 25 basis points to 8.5 percent, which also increased our pension and postretirement benefit cost.

The increase in total net periodic pension and other benefits cost during fiscal 2005 compared with fiscal 2004 primarily reflects an increase in our service cost associated with the increase in the number of employees covered by our plans due to the TXU Gas acquisition. Although we did not assume the existing employee benefit liabilities or plans of TXU Gas, for purposes of determining our annual pension cost we agreed to give the transitioned employees credit for years of TXU Gas service under our pension plan. With respect to our postretirement medical plan, we received a credit of $18.9 million against the purchase price to permit us to provide partial past service credits for retiree medical benefits under our retiree medical plan. The $18.9 million credit approximated the actuarially determined present value of the accumulated benefits related to the past service of the transferred employees on the acquisition date.

In addition to the increased number of employees covered by the plans, we changed the assumptions used to determine our fiscal 2005 benefit costs, which resulted in an increase in our net periodic pension and postretirement costs. We increased the discount rate by 25 basis points and we reduced our expected return on our pension plan assets by 25 basis points. These assumption changes decreased the service cost and interest cost and reduced the expected return components of our pension and postretirement benefits costs.

***Pension and Postretirement Plan Funding***

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2006, we voluntarily contributed $2.9 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities.

We contributed $10.9 million, $10.0 million and $13.8 million to our postretirement benefits plans for the years ended September 30, 2006, 2005 and 2004. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by our regulators.

***Outlook for Fiscal 2007***

High grade corporate bond yields increased in the period leading up to our June 30, 2006 measurement date. Therefore, we increased the discount rate for determining our fiscal 2007 pension and benefit costs by 130 basis points to 6.3 percent. However, we reduced the expected return on our pension plan assets by 25 basis points to 8.25 percent. The effect of these assumption changes, coupled with the effects of updating our annual valuation should not significantly affect our fiscal 2007 net pension and postretirement costs compared to fiscal 2006.

We are not required to make a minimum funding contribution to our pension plans during fiscal 2007; nor, at this time, do we intend to make voluntary contributions during 2007. However, we anticipate contributing approximately $11 million to our postretirement medical plans during fiscal 2007.

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

## 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 consolidated financial statements.

## ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

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

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to protect us and our customers against unusually large winter period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the condensed consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper, the issuance of floating rate debt in October 2004 and our other short-term borrowings.

### Commodity Price Risk

#### *Utility segment*

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

For our utility segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas cost related to fixed-price non-regulated sales. Based on these projected non-regulated gas sales, a hypothetical 10 percent increase in fixed prices based upon the September 30, 2006 three month market strip, would increase our purchased gas cost by approximately $2.3 million in fiscal 2007.

#### *Natural gas marketing and pipeline and storage segments*

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2006 of 0.2 Bcf, a $0.50 change in the forward NYMEX price would have had less than a $0.1 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2006 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $5.0 million.

Additionally, these changes could cause us to recognize a risk management liability, which would require us to place cash into an escrow account to collateralize this liability position. This, in turn, would reduce the amount of cash we would have on hand to fund our working capital needs. Because we recognized risk management liabilities as of September 30, 2006, we placed $35.6 million in escrow to collateralize these liabilities.

**Interest Rate Risk**

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $3.6 million during 2006.

We also assess market risk for our fixed and floating rate long-term obligations. We estimate market risk for our long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our long-term obligations would have increased by approximately $143.3 million.

As of September 30, 2006, we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

## ITEM 8. *Financial Statements and Supplementary Data*

Index to financial statements and financial statement schedule:



All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and accompanying notes thereto.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON CONSOLIDATED FINANCIAL STATEMENTS

The Board of Directors
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2006 and 2005, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atmos Energy Corporation's internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 20, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 20, 2006

## ATMOS ENERGY CORPORATION

## CONSOLIDATED BALANCE SHEETS

| | September 30 2006 | September 30 2005 |
|---|---|---|
| | (In thousands, except share data) | |
| **ASSETS** | | |
| Property, plant and equipment | $5,026,478 | $4,631,684 |
| Construction in progress | 74,830 | 133,926 |
| | 5,101,308 | 4,765,610 |
| Less accumulated depreciation and amortization | 1,472,152 | 1,391,243 |
| Net property, plant and equipment | 3,629,156 | 3,374,367 |
| Current assets | | |
| Cash and cash equivalents | 75,815 | 40,116 |
| Cash held on deposit in margin account | 35,647 | 80,956 |
| Accounts receivable, less allowance for doubtful accounts of $13,686 in 2006 and $15,613 in 2005 | 374,629 | 454,313 |
| Gas stored underground | 461,502 | 450,807 |
| Other current assets | 169,952 | 238,238 |
| Total current assets | 1,117,545 | 1,264,430 |
| Goodwill and intangible assets | 738,521 | 737,787 |
| Deferred charges and other assets | 234,325 | 276,943 |
| | $5,719,547 | $5,653,527 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Shareholders' equity | | |
| Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2006 — 81,739,516 shares, 2005 — 80,539,401 shares | $ 409 | $ 403 |
| Additional paid-in capital | 1,467,240 | 1,426,523 |
| Accumulated other comprehensive loss | (43,850) | (3,341) |
| Retained earnings | 224,299 | 178,837 |
| Shareholders' equity | 1,648,098 | 1,602,422 |
| Long-term debt | 2,180,362 | 2,183,104 |
| Total capitalization | 3,828,460 | 3,785,526 |
| Commitments and contingencies | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | 345,108 | 461,314 |
| Other current liabilities | 388,451 | 503,368 |
| Short-term debt | 382,416 | 144,809 |
| Current maturities of long-term debt | 3,186 | 3,264 |
| Total current liabilities | 1,119,161 | 1,112,755 |
| Deferred income taxes | 306,172 | 292,207 |
| Regulatory cost of removal obligation | 261,376 | 263,424 |
| Deferred credits and other liabilities | 204,378 | 199,615 |
| | $5,719,547 | $5,653,527 |

See accompanying notes to consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONSOLIDATED STATEMENTS OF INCOME

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands, except per share data) | | |
| Operating revenues | | | |
| Utility segment | $3,650,591 | $3,103,140 | $1,637,728 |
| Natural gas marketing segment | 3,156,524 | 2,106,278 | 1,618,602 |
| Pipeline and storage segment | 160,567 | 153,289 | 19,758 |
| Other nonutility segment | 5,898 | 5,302 | 3,393 |
| Intersegment eliminations | (821,217) | (406,136) | (359,444) |
| | 6,152,363 | 4,961,873 | 2,920,037 |
| Purchased gas cost | | | |
| Utility segment | 2,725,534 | 2,195,774 | 1,134,594 |
| Natural gas marketing segment | 3,025,897 | 2,044,305 | 1,571,971 |
| Pipeline and storage segment | 838 | 6,811 | 9,383 |
| Other nonutility segment | — | — | — |
| Intersegment eliminations | (816,476) | (402,654) | (358,102) |
| | 4,935,793 | 3,844,236 | 2,357,846 |
| Gross profit | 1,216,570 | 1,117,637 | 562,191 |
| Operating expenses | | | |
| Operation and maintenance | 433,418 | 416,281 | 214,470 |
| Depreciation and amortization | 185,596 | 178,005 | 96,647 |
| Taxes, other than income | 191,993 | 174,696 | 57,379 |
| Impairment of long-lived assets | 22,947 | — | — |
| Total operating expenses | 833,954 | 768,982 | 368,496 |
| Operating income | 382,616 | 348,655 | 193,695 |
| Miscellaneous income | 881 | 2,021 | 9,507 |
| Interest charges | 146,607 | 132,658 | 65,437 |
| Income before income taxes | 236,890 | 218,018 | 137,765 |
| Income tax expense | 89,153 | 82,233 | 51,538 |
| Net income | $ 147,737 | $ 135,785 | $ 86,227 |
| Per share data | | | |
| Basic net income per share | $ 1.83 | $ 1.73 | $ 1.60 |
| Diluted net income per share | $ 1.82 | $ 1.72 | $ 1.58 |
| Weighted average shares outstanding: | | | |
| Basic | 80,731 | 78,508 | 54,021 |
| Diluted | 81,390 | 79,012 | 54,416 |

See accompanying notes to consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

| | Common Stock | | Additional | Accumulated Other | | |
|---|---|---|---|---|---|---|
| | Number of Shares | Stated Value | Paid-in Capital | Comprehensive Loss | Retained Earnings | Total |
| | (In thousands, except share data) | | | | | |
| **Balance, September 30, 2003** | 51,475,785 | $257 | $ 736,180 | $ (1,459) | $ 122,539 | $ 857,517 |
| **Comprehensive income:** | | | | | | |
| Net income | — | — | — | — | 86,227 | 86,227 |
| Unrealized holding gains on investments, net | — | — | — | 615 | — | 615 |
| Treasury lock agreements, net | — | — | — | (21,268) | — | (21,268) |
| Cash flow hedges, net | — | — | — | 7,583 | — | 7,583 |
| **Total comprehensive income** | | | | | | 73,157 |
| **Cash dividends ($1.22 per share)** | — | — | — | — | (66,736) | (66,736) |
| **Common stock issued:** | | | | | | |
| Public offering | 9,939,393 | 50 | 235,419 | — | — | 235,469 |
| Direct stock purchase plan | 556,856 | 3 | 13,726 | — | — | 13,729 |
| Retirement savings plan | 320,313 | 2 | 8,300 | — | — | 8,302 |
| 1998 Long-term incentive plan | 498,230 | 2 | 11,848 | — | — | 11,850 |
| Long-term stock plan for Mid-States Division | 6,000 | — | 94 | — | — | 94 |
| Outside directors stock-for-fee plan | 3,133 | — | 77 | — | — | 77 |
| **Balance, September 30, 2004** | 62,799,710 | 314 | 1,005,644 | (14,529) | 142,030 | 1,133,459 |
| **Comprehensive income:** | | | | | | |
| Net income | — | — | — | — | 135,785 | 135,785 |
| Unrealized holding gains on investments, net | — | — | — | 1,528 | — | 1,528 |
| Treasury lock agreements, net | — | — | — | (2,714) | — | (2,714) |
| Cash flow hedges, net | — | — | — | 12,374 | — | 12,374 |
| **Total comprehensive income** | | | | | | 146,973 |
| **Cash dividends ($1.24 per share)** | — | — | — | — | (98,978) | (98,978) |
| **Common stock issued:** | | | | | | |
| Public offering | 16,100,000 | 80 | 381,271 | — | — | 381,351 |
| Direct stock purchase plan | 450,212 | 3 | 12,486 | — | — | 12,489 |
| Retirement savings plan | 441,350 | 2 | 11,767 | — | — | 11,769 |
| 1998 Long-term incentive plan | 745,788 | 4 | 14,116 | — | — | 14,120 |
| Stock-based compensation | — | — | 1,175 | — | — | 1,175 |
| Outside directors stock-for-fee plan | 2,341 | — | 64 | — | — | 64 |
| **Balance, September 30, 2005** | 80,539,401 | 403 | 1,426,523 | (3,341) | 178,837 | 1,602,422 |
| **Comprehensive income:** | | | | | | |
| Net income | — | — | — | — | 147,737 | 147,737 |
| Unrealized holding gains on investments, net | — | — | — | 882 | — | 882 |
| Treasury lock agreements, net | — | — | — | 3,442 | — | 3,442 |
| Cash flow hedges, net | — | — | — | (44,833) | — | (44,833) |
| **Total comprehensive income** | | | | | | 107,228 |
| **Cash dividends ($1.26 per share)** | — | — | — | — | (102,275) | (102,275) |
| **Common stock issued:** | | | | | | |
| Direct stock purchase plan | 387,833 | 2 | 10,391 | — | — | 10,393 |
| Retirement savings plan | 442,635 | 2 | 11,918 | — | — | 11,920 |
| 1998 Long-term incentive plan | 366,905 | 2 | 8,976 | — | — | 8,978 |
| Long-term stock plan for Mid-States Division | 300 | — | 5 | — | — | 5 |
| Stock-based compensation | — | — | 9,361 | — | — | 9,361 |
| Outside directors stock-for-fee plan | 2,442 | — | 66 | — | — | 66 |
| **Balance, September 30, 2006** | 81,739,516 | $409 | $1,467,240 | $(43,850) | $ 224,299 | $1,648,098 |

See accompanying notes to consolidated financial statements

## ATMOS ENERGY CORPORATION

## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (In thousands) | |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $ 147,737 | $ 135,785 | $ 86,227 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Gain on sales of assets | — | — | (6,700) |
| Impairment of long-lived assets | 22,947 | — | — |
| Depreciation and amortization: | | | |
| Charged to depreciation and amortization | 185,596 | 178,005 | 96,647 |
| Charged to other accounts | 371 | 791 | 1,465 |
| Deferred income taxes | 86,178 | 12,669 | 36,997 |
| Other | 18,480 | 11,522 | (1,772) |
| Changes in assets and liabilities: | | | |
| (Increase) decrease in cash held on deposit in margin account | 45,309 | (80,956) | 17,903 |
| (Increase) decrease in accounts receivable | 78,407 | (166,692) | 2,158 |
| Increase in gas stored underground | (10,695) | (112,796) | (31,030) |
| Increase in other current assets | (52,449) | (56,828) | (9,233) |
| Decrease in deferred charges and other assets | 28,614 | 30,059 | 17,178 |
| Increase (decrease) in accounts payable and accrued liabilities | (116,060) | 224,375 | 4,586 |
| Increase (decrease) in other current liabilities | (113,977) | 218,715 | 48,877 |
| Increase (decrease) in deferred credits and other liabilities | (9,009) | (7,705) | 7,431 |
| Net cash provided by operating activities | 311,449 | 386,944 | 270,734 |
| CASH FLOWS USED IN INVESTING ACTIVITIES | | | |
| Capital expenditures | (425,324) | (333,183) | (190,285) |
| Acquisitions, net of cash received | — | (1,916,696) | (1,957) |
| Proceeds from sales of assets | — | — | 27,919 |
| Other, net | (5,767) | (2,131) | (570) |
| Net cash used in investing activities | (431,091) | (2,252,010) | (164,893) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Net increase (decrease) in short-term debt | 237,607 | 144,809 | (118,595) |
| Net proceeds from issuance of long-term debt | — | 1,385,847 | 5,000 |
| Settlement of Treasury lock agreements | — | (43,770) | — |
| Repayment of long-term debt | (3,264) | (103,425) | (9,713) |
| Cash dividends paid | (102,275) | (98,978) | (66,736) |
| Issuance of common stock | 23,273 | 37,183 | 34,715 |
| Net proceeds from equity offering | — | 381,584 | 235,737 |
| Net cash provided by financing activities | 155,341 | 1,703,250 | 80,408 |
| Net increase (decrease) in cash and cash equivalents | 35,699 | (161,816) | 186,249 |
| Cash and cash equivalents at beginning of year | 40,116 | 201,932 | 15,683 |
| Cash and cash equivalents at end of year | $ 75,815 | $ 40,116 | $ 201,932 |

See accompanying notes to consolidated financial statements

## ATMOS ENERGY CORPORATION

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Nature of Business

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

| Division | Service Area |
|---|---|
| Atmos Energy Colorado-Kansas Division | Colorado, Kansas, Missouri[2] |
| Atmos Energy Kentucky Division[1] | Kentucky |
| Atmos Energy Louisiana Division | Louisiana |
| Atmos Energy Mid-States Division[1] | Georgia[2], Illinois[2], Iowa[2], Missouri[2], Tennessee, Virginia[2] |
| Atmos Energy Mid-Tex Division | Texas, including the Dallas/Fort Worth metropolitan area |
| Atmos Energy Mississippi Division | Mississippi |
| Atmos Energy West Texas Division | West Texas |

(1) Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

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

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

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

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

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

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

Prior to January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of AEH, owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with three other utility companies. Through our ownership in USP, we owned an approximate five percent indirect interest in Heritage Propane Partners, L.P. (Heritage). During 2004, we sold our interest in USP and Heritage. We received cash proceeds of $26.6 million and recorded a pretax book gain of $5.9 million with these transactions. We no longer have an interest in the propane industry.

## 2. Summary of Significant Accounting Policies

*Principles of consolidation* — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated.

*Use of estimates* — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligation, impairment of long-lived assets, risk management and trading activities and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

*Regulation* — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Regulated utility operations are accounted for in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires 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 regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2006 and 2005 included the following:

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| **Regulatory assets:** | | |
| Merger and integration costs, net | $ 8,644 | $ 9,150 |
| Deferred gas costs | 44,992 | 38,173 |
| Environmental costs | 1,234 | 1,357 |
| Rate case costs | 10,579 | 11,314 |
| Deferred franchise fees | 1,311 | 6,710 |
| Other | 9,055 | 9,313 |
| | $ 75,815 | $ 76,017 |
| **Regulatory liabilities:** | | |
| Deferred gas costs | $ 68,959 | $134,048 |
| Regulatory cost of removal obligation | 276,490 | 274,989 |
| Deferred income taxes, net | 235 | 3,185 |
| Other | 10,825 | 8,084 |
| | $356,509 | $420,306 |

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. During the fiscal years ended September 30, 2006, 2005 and 2004, we recognized $0.5 million, $2.3 million and $8.2 million in amortization expense related to these costs. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various regulatory commissions.

As of September 30, 2006, our Mid-States Division had open rate cases in its Missouri and Tennessee service areas seeking rate increases of $3.4 million in each jurisdiction. The Tennessee rate was settled in October 2006 and resulted in a $6.1 million reduction in future annual revenues. We anticipate that the Missouri rate case will be finalized in February 2007. In addition, during 2006 our Mid-Tex Division filed a system-wide case seeking incremental annual revenues of approximately $60 million and several rate design changes. A ruling on this filing is anticipated by April 2007.

*Revenue recognition* — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. Revenue is recognized in our pipeline and storage segment as the services are provided.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulators and are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues. For the years ended September 30, 2006, 2005 and 2004, we included unrealized gains (losses) on open contracts of $17.2 million, ($26.0) million and ($2.8) million as a component of natural gas marketing revenues.

*Cash and cash equivalents* — We consider all highly liquid investments with an initial or remaining maturity of three months or less to be cash equivalents.

*Cash held on deposit in margin account* — Cash held on deposit in margin account consists of deposits made to collateralize certain financial derivatives purchased in support of our risk management activities. Under the terms of these derivative contracts, when the fair value of financial instruments held represents a net liability position, we are required to deposit cash into a margin account.

*Accounts receivable and allowance for doubtful accounts* — Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal, agricultural and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

*Gas stored underground* — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our utility operations and natural gas held by our natural gas marketing and other nonutility subsidiaries to conduct their operations. The average cost method is used for all our utility divisions, except for certain jurisdictions in the Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. The average gas cost method is also used for our natural gas marketing segment and our Atmos Pipeline — Texas Division. Our Natural Gas Marketing segment utilizes the average cost method; however, most of this inventory is hedged and is therefore marked to market at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

*Utility property, plant and equipment* — Utility property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $3.6 million, $2.5 million and $1.2 million was capitalized in 2006, 2005 and 2004.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the utility plant in service account included in the rate base and depreciation begins.

Utility property, plant and equipment is depreciated at various rates on a straight-line basis over the estimated useful lives of the assets. These rates are approved by our regulatory commissions and are comprised of two components, one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.9 percent, 4.0 percent and 3.8 percent for the years ended September 30, 2006, 2005 and 2004.

*Nonutility property, plant and equipment* — Nonutility property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from 8 to 38 years.

*Asset retirement obligations* — SFAS 143, *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations*, which became effective for us September 30, 2006, require that we record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2006, we adopted the provisions of FIN 47. As a result of adopting FIN 47, we recorded an asset retirement obligation of $15.1 million associated with our distribution system. As retirement costs incurred by the distribution system are recovered from utility customers, this liability had previously been captured in our regulatory cost of removal liability. As a result of adopting FIN 47, we reclassified the $15.1 million from regulatory cost of removal liability to asset retirement obligation. In addition, we recorded $4.8 million of asset retirement costs that will be depreciated over the remaining life of the underlying associated asset lives. We believe we have a legal obligation to retire our storage wells. However, we have not recognized an asset retirement obligation associated with our storage wells because there is not sufficient industry history to reasonably estimate the fair value of this obligation. The adoption of FIN 47 did not have an impact to our results operations as the cost of removal expense has previously been recorded as described above. In accordance with the transition guidance of FIN 47, prior periods have not been restated; however, the asset retirement obligation as of September 30, 2005 would have been $14.6 million.

*Impairment of long-lived assets* — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

During the fourth quarter of fiscal 2006, we determined that, as a result of declining irrigation sales primarily associated with our agricultural customers' shift from gas-powered pumps to electric pumps, the West Texas Division's irrigation assets would not be able to generate sufficient future cash flows from operations to recover the net investment in these assets. Therefore, we recorded a $22.9 million charge to impairment to write off the entire net book value. We will continue to operate these assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets.

*Goodwill and intangible assets* — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Intangible assets are amortized over their useful lives of 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. To date, no impairment has been recognized.

*Marketable securities* — As of September 30, 2006 and 2005, all of our marketable securities were classified as available-for-sale securities based upon the criteria of SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities.* In accordance with that standard, 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.

*Derivatives and hedging activities* — Our derivative and hedging activities are tailored to the segment to which they relate. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change did not have a material impact on our financial position on the date of adoption.

***Utility Segment***

In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities.* Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. However, because the gains or losses of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related gain or loss is recovered through our rates.

***Natural Gas Marketing Segment***

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

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Under SFAS 133, natural gas inventory is designated as the hedged item in a fair-value hedge and is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in revenue in the period of change. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact on our financial position on the date of adoption. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change. When evaluating effectiveness, we exclude the differential between the spot price used to value our physical inventory and the forward price used to value the financial hedges designated against our physical inventory.

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

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

Additionally, we utilize 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. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue of our natural gas marketing segment.

In our natural gas marketing segment, hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments (referred to as basis ineffectiveness) for our fair value hedges resulted in an unrealized gain of \$15.5 million for the year ended September 30, 2006 compared with an unrealized loss of \$1.7 million and \$0.6 million for the years ended September 30, 2005 and 2004. Basis ineffectiveness for our cash flow hedges resulted in an unrealized gain of approximately \$20.0 million for the year ended September 30, 2006 compared with an unrealized loss of approximately \$3.7 million and \$0.5 million for the years ended September 30, 2005 and 2004. Hedge ineffectiveness arising from the timing of the settlement of physical contracts and the settlement of the related fair value hedge resulted in an unrealized gain of approximately \$4.4 million and \$0.5 million for the years ended September 30, 2006 and 2004 and an unrealized loss of approximately \$2.2 million for the year ended September 30, 2005. The increased ineffectiveness is due to the high level of market volatility experienced in 2006.

Additionally, we have a policy which allows for the use of master netting agreements with significant counterparties that allow us to offset gains and losses arising from derivative instruments that may be settled in cash and/or gains and losses arising from derivative instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place.

***Pipeline and Storage Segment***

Similar to AEM, Atmos Pipeline and Storage, LLC has designated its natural gas inventory as the hedged item in a fair-value hedge. The inventory is marked to market at the end of each month based upon Gas Daily index. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of natural gas inventory should be offset by gains and losses on the fair-value hedges; resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

In our pipeline and storage segment, actual hedge ineffectiveness arising from the timing of settlement of physical contracts and the settlement of the derivative instruments resulted in a loss of approximately $4.7 million for the year ended September 30, 2006, a gain of approximately $5.2 million for the year ended September 30, 2005 and a loss of less than $0.1 million for the year ended September 30, 2004.

*Treasury Activities*

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under present market conditions.

*Pension and other postretirement plans* — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan cost over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

*Income taxes* — Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

*Stock-based compensation plans* — We maintain the 1998 Long-Term Incentive Plan that provides for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to officers, division presidents and other key employees. Non-employee directors are also eligible to receive stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

On October 1, 2005, the Company adopted SFAS 123 (revised), *Share-Based Payment* (SFAS 123(R)). This standard revises SFAS 123, *Accounting for Stock-Based Compensation* and supersedes Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees.* Under SFAS 123(R), the Company is required to measure the cost of employee services received in exchange for stock options and similar awards based on the grant-date fair value of the award and recognize this cost in the income statement over the period during which an employee is required to provide service in exchange for the award.

We adopted SFAS 123(R) using the modified prospective method. Under this transition method, stock-based compensation expense for the year ended September 30, 2006 included: (i) compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of October 1, 2005, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123; and (ii) compensation expense for all stock-based compensation awards granted subsequent to October 1, 2005, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). We recognize compensation expense on a straight-line basis over the requisite service period of the award. The impact of adoption on total stock-based compensation expense included in our statement of income for the year ended September 30, 2006 was $0.4 million and was recorded as a component of operation and maintenance expense. In accordance with the modified prospective method, financial results for prior periods have not been restated.

Prior to October 1, 2005, we accounted for these plans under the intrinsic-value method described in APB Opinion 25, as permitted by SFAS 123. Under this method, no compensation cost for stock options was recognized for stock-option awards granted at or above fair-market value. Awards of restricted stock were valued at the market price of the Company's common stock on the date of grant. The unearned compensation was amortized as a component of operation and maintenance expense over the vesting period of the restricted stock.

Total stock-based compensation expense for the year ended September 30, 2006 was $9.4 million as compared to $3.9 million and $1.6 million for the years ended September 30, 2005 and 2004. Had compensation expense for our stock-based awards been recognized as prescribed by SFAS 123, our net income and earnings per share for the years ended September 30, 2005 and 2004 would have been impacted as shown in the following table:

| | Year Ended September 30 | |
|---|---|---|
| | 2005 | 2004 |
| | (In thousands, except per share data) | |
| Net income — as reported | $135,785 | $86,227 |
| Restricted stock compensation expense included in income, net of tax | 2,431 | 978 |
| Total stock-based employee compensation expense determined under fair-value- based method for all awards, net of taxes | (3,161) | (2,092) |
| Net income — pro forma | $135,055 | $85,113 |
| Earnings per share: | | |
| Basic earnings per share — as reported | $ 1.73 | $ 1.60 |
| Basic earnings per share — pro forma | $ 1.72 | $ 1.57 |
| Diluted earnings per share — as reported | $ 1.72 | $ 1.58 |
| Diluted earnings per share — pro forma | $ 1.71 | $ 1.56 |

*Accumulated other comprehensive loss* — Accumulated other comprehensive loss, net of tax, as of September 30, 2006 and 2005 consisted of the following unrealized gains (losses):

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Unrealized holding gains on investments | $ 1,566 | $ 684 |
| Treasury lock agreements | (20,540) | (23,982) |
| Cash flow hedges | (24,876) | 19,957 |
| | $(43,850) | $ (3,341) |

*Recent accounting pronouncements* — In February 2006, the FASB issued SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* SFAS 155 (a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, (b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS 133, (c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, (d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives and (e) amends SFAS 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS 155 is effective for all financial instruments acquired or issued by us after October 1, 2006 and the adoption of this standard is not expected to have a material impact on our financial position, results of operations and cash flows.

In March 2006, the FASB issued SFAS 156, *Accounting for Servicing Financial Assets*, which amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* SFAS 156 (a) revises guidance on when a servicing asset and servicing liability should be recognized, (b) requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value, if practicable, (c) permits an entity to choose to measure servicing assets and servicing liabilities under the amortization method or fair value measurement method, (d) at initial adoption, permits a one-time reclassification of available-for-sale securities to trading securities by entities with recognized servicing rights, without calling into question the treatment of other available-for-sale securities under SFAS 115, provided that the available-for-sale securities are identified as offsetting the exposure to changes in the fair value of servicing assets or liabilities that the servicer elects to subsequently measure at fair value and (e) requires separate presentation of servicing assets and servicing liabilities subsequently measured at fair value in the statement of financial position and additional footnote disclosure. We will be required to apply the provisions of SFAS 156 beginning October 1, 2006 and such application is expected not to have a material impact on our financial position, results of operations and cash flows.

In June 2006, the Emerging Issues Task Force (EITF) ratified EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).* The EITF reached a consensus that the scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include sales, use, value added and some excise taxes. The EITF also reached a consensus that entities may present these taxes on either a gross or net basis. If the taxes are significant, an entity should disclose its policy of presenting taxes and the amounts of taxes that are recognized on a gross basis in interim and annual financial statements. We will be required to apply the provisions of EITF 06-3 beginning January 1, 2007. We are currently evaluating the impact this standard may have on our results of operations.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on de-recognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements.* SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measurements required under other accounting pronouncements but does not change existing guidance as to whether or not an instrument is carried at fair value. We will be required to apply the provisions of SFAS 157 beginning October 1, 2008. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* The new standard makes a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date. This standard does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition guidance of this standard will be effective for fiscal 2007 and the measurement date provisions of this guidance can be adopted as late as fiscal 2008 for our company.

## 3. Acquisitions

### *TXU Gas Company*

In October 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company. The purchase price for the TXU Gas acquisition was approximately $1.9 billion (after closing adjustments and before transaction costs and expenses), which we paid in cash. We did not assume any indebtedness of TXU Gas in connection with the acquisition. The purchase was accounted for as an asset purchase. We funded the purchase price for the TXU Gas acquisition with approximately $235.7 million in net proceeds from our offering of approximately 9.9 million shares of common stock, which we completed in July 2004, and approximately $1.7 billion in net proceeds from our issuance in October 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 to provide bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes in October 2004, which generated net proceeds of approximately $1.39 billion, and the sale of 16.1 million shares of common stock in October 2004, which generated net proceeds of $381.6 million.

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

| | |
|---|---|
| Cash purchase price | $1,908,999 |
| Transaction costs and expenses | 7,697 |
| Total purchase price | $1,916,696 |
| Net property, plant and equipment | $1,471,643 |
| Accounts receivable | 75,811 |
| Gas stored underground | 137,877 |
| Other current assets | 22,094 |
| Goodwill | 493,603 |
| Deferred charges and other assets | 42,069 |
| Deferred income taxes | 7,925 |
| Accounts payable and accrued liabilities | (51,644) |
| Other current liabilities | (77,756) |
| Regulatory cost of removal obligation | (138,991) |
| Deferred credits and other liabilities | (65,935) |
| Total | $1,916,696 |

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

At closing of the acquisition, TXU Gas and some of its affiliates entered into transitional services agreements with us to provide call center, meter reading, customer billing, collections, information reporting, software, accounting, treasury, administrative and other services to the Mid-Tex Division. Some of these services were outsourced by TXU Gas to Capgemini Energy L.P. However, in November 2004, we entered into an agreement with Capgemini Energy L.P. whereby we assumed the operations of the Waco, Texas call center in April 2005 and purchased from Capgemini Energy L.P. all of the related call center assets in October 2005. The remaining transitional services agreements expired in September 2005 and were not renewed as we in-sourced all of these functions, effective October 2005.

The table below reflects the unaudited pro forma results of the Company and TXU Gas for the year ended September 30, 2004 as if the acquisition and related financing had taken place at the beginning of fiscal 2004 (in thousands, except per share data):

| | Year Ended September 30, 2004 |
|---|---|
| Operating revenue | $4,174,500 |
| Net income | 118,746 |
| Net income per diluted share | $ 1.68 |

***ComFurT Gas Inc.***

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

## 4. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2006 and 2005.

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Goodwill | $735,369 | $734,280 |
| Intangible assets | 3,152 | 3,507 |
| Total | $738,521 | $737,787 |

The following presents our goodwill balance allocated by segment and changes in the balance for the year ended September 30, 2006:

| | Utility Segment | Natural Gas Marketing Segment | Pipeline and Storage Segment | Other Nonutility Segment | Total |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| Balance as of September 30, 2005 | $566,800 | $24,282 | $143,198 | $— | $734,280 |
| Deferred tax adjustments on prior acquisitions[1] | 421 | — | 668 | — | 1,089 |
| Balance as of September 30, 2006 | $567,221 | $24,282 | $143,866 | $— | $735,369 |

[1] During the preparation of the fiscal 2006 tax provision, we adjusted certain deferred taxes recorded in connection with a fiscal 2001 and a fiscal 2004 acquisitions which resulted in an increase to goodwill and net deferred tax liabilities of $1.1 million.

Information regarding our intangible assets is included in the following table. As of September 30, 2006 and 2005, we had no indefinite-lived intangible assets.

| | | September 30, 2006 | | | September 30, 2005 | | |
|---|---|---|---|---|---|---|---|
| | Useful Life (Years) | Gross Carrying Amount | Accumulated Amortization | Net | Gross Carrying Amount | Accumulated Amortization | Net |
| | | (In thousands) | | | | | |
| Customer contracts | 10 | $6,754 | $(3,602) | $3,152 | $6,521 | $(3,014) | $3,507 |

The following table presents actual amortization expense recognized during 2006 and an estimate of future amortization expense based upon our intangible assets at September 30, 2006.

**Amortization expense (in thousands):**

| | |
|---|---|
| Actual for the fiscal year ending September 30, 2006 | $588 |
| Estimated for the fiscal year ending: | |
| September 30, 2007 | 608 |
| September 30, 2008 | 608 |
| September 30, 2009 | 608 |
| September 30, 2010 | 608 |
| September 30, 2011 | 608 |

## 5. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. These activities are described in more detail in Note 2. Also, as discussed in Note 2, we record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2006 and 2005:

| | Utility | Natural Gas Marketing | Total |
|---|---|---|---|
| | | (In thousands) | |
| **September 30, 2006:** | | | |
| Assets from risk management activities, current | $ — | $ 12,553 | $ 12,553 |
| Assets from risk management activities, noncurrent | — | 6,186 | 6,186 |
| Liabilities from risk management activities, current | (27,209) | (3,460) | (30,669) |
| Liabilities from risk management activities, noncurrent | — | (276) | (276) |
| Net assets (liabilities) | $(27,209) | $ 15,003 | $(12,206) |
| **September 30, 2005:** | | | |
| Assets from risk management activities, current | $ 93,310 | $ 14,603 | $107,913 |
| Assets from risk management activities, noncurrent | — | 735 | 735 |
| Liabilities from risk management activities, current | — | (61,920) | (61,920) |
| Liabilities from risk management activities, noncurrent | — | (15,316) | (15,316) |
| Net assets (liabilities) | $ 93,310 | $(61,898) | $ 31,412 |

### *Utility Hedging Activities*

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. For the 2005-2006 heating season, we hedged approximately 46 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately $9.06 per Mcf.

Our utility hedging activities also includes the fair value of our treasury lock agreements which are described in further detail below.

### *Nonutility Hedging Activities*

For the year ended September 30, 2006, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts totaling $51.0 million and the recognition of $6.2 million in net deferred hedging losses in net income when the derivatives matured according to their terms. The net deferred hedging losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Substantially all of the deferred hedging loss as of September 30, 2006 is expected to be recognized in net income within the next fiscal year.

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

At the close of business on September 30, 2006, AEH had a net open position (including existing storage) of 0.2 Bcf.

### *Treasury Activities*

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the-then anticipated issuance of $875 million of long-term debt subsequent to September 30, 2004. This long-term debt was issued in October 2004 and was used to repay a portion of the commercial paper used to fund the TXU Gas acquisition, as described in Note 3.

We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury locks were recorded as a component of accumulated other comprehensive loss. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement.

The following table presents our hedging transactions that were recorded to other comprehensive income (loss), net of taxes during the years ended September 30, 2006 and 2005.

| | Year Ended September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| *Increase (decrease) in fair value:* | | |
| Treasury lock agreements | $ — | $ (5,869) |
| Forward commodity contracts | (51,014) | 1,988 |
| *Recognition of (gains) losses in earnings due to settlements:* | | |
| Treasury lock agreements | 3,442 | 3,155 |
| Forward commodity contracts | 6,181 | 10,386 |
| Total other comprehensive income (loss) from hedging, net of tax[(1)] | $(41,391) | $ 9,660 |

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

The following amounts, net of deferred taxes, represent the expected recognition into earnings for our derivative instruments, based upon the fair values of these derivatives as of September 30, 2006:

| | Treasury Lock Agreements | Forward Contracts | Total |
|---|---|---|---|
| | | (In thousands) | |
| 2007 | $ (3,442) | $(24,100) | $(27,542) |
| 2008 | (3,442) | (732) | (4,174) |
| 2009 | (3,442) | (38) | (3,480) |
| 2010 | (2,123) | (6) | (2,129) |
| 2011 | (2,003) | — | (2,003) |
| Thereafter | (6,088) | — | (6,088) |
| Total | $(20,540) | $(24,876) | $(45,416) |

## 6. Debt

### *Long-term debt*

Long-term debt at September 30, 2006 and 2005 consisted of the following:

| | 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| Unsecured floating rate Senior Notes, due October 2007 | $ 300,000 | $ 300,000 |
| Unsecured 4.00% Senior Notes, due 2009 | 400,000 | 400,000 |
| Unsecured 7.375% Senior Notes, due 2011 | 350,000 | 350,000 |
| Unsecured 10% Notes, due 2011 | 2,303 | 2,303 |
| Unsecured 5.125% Senior Notes, due 2013 | 250,000 | 250,000 |
| Unsecured 4.95% Senior Notes, due 2014 | 500,000 | 500,000 |
| Unsecured 5.95% Senior Notes, due 2034 | 200,000 | 200,000 |
| Medium term notes | | |
| Series A, 1995-2, 6.27%, due 2010 | 10,000 | 10,000 |
| Series A, 1995-1, 6.67%, due 2025 | 10,000 | 10,000 |
| Unsecured 6.75% Debentures, due 2028 | 150,000 | 150,000 |
| First Mortgage Bonds Series P, 10.43% due 2013 | 8,750 | 10,000 |
| Rental property, propane and other term notes due in installments through 2013 | 5,825 | 7,839 |
| Total long-term debt | 2,186,878 | 2,190,142 |
| Less: | | |
| Original issue discount on unsecured senior notes and debentures | (3,330) | (3,774) |
| Current maturities | (3,186) | (3,264) |
| | $2,180,362 | $2,183,104 |

In December 2001, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC in January 2002. In July 2004, we sold 9.9 million shares of our common stock. We used the net proceeds from this offering, together with borrowings under a bridge financing facility to consummate the acquisition of TXU Gas operations and pay related fees and expenses. As a result of the offering, we exhausted the remaining availability under our December 2001 registration statement.

In August 2004, we filed another registration statement with the SEC, which was declared effective by the SEC in September 2004, under which we could issue, from time to time, up to $2.2 billion in new common stock and/or debt. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option, under the new registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the registration statement consisting of $400 million of 4.00% Senior Notes due 2009, $500 million of 4.95% Senior Notes due 2014, $200 million of 5.95% Senior Notes due 2034 and $300 million of floating rate Senior Notes due 2007. The floating rate notes bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At September 30, 2006, the interest rate on our floating rate debt was 5.882 percent. The net proceeds from the sale of these senior notes were $1.39 billion.

The net proceeds from the October 2004 common stock and senior notes offerings, combined with the net proceeds from our July 2004 offering were used to pay off the $1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 for bridge financing for the TXU Gas acquisition. Also, as a result of this refinancing in October 2004, we canceled the senior unsecured revolving credit facility. After issuing the debt and equity in October 2004 we had approximately $401.5 million in availability remaining under the registration statement. However, we are no longer allowed to issue securities under that registration statement by applicable state regulatory commissions. See further discussion in the Liquidity section of Management's Discussion and Analysis.

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

***Short-term debt***

At September 30, 2006 and 2005, there was $379.3 million and $129.9 million outstanding under our commercial paper program and $3.1 million and $14.9 million outstanding under our bank credit facilities. As of September 30, 2006, our commercial paper had maturities of less than three months, with interest rates ranging from 5.47 percent to 5.51 percent.

***Credit facilities***

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

*Committed credit facilities*

As of September 30, 2006, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a three-year unsecured facility, expiring October 2008, for $600 million that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.40 percent to 1.00 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At September 30, 2006, there was $379.3 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility for $300 million that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This facility expired in November 2006 and was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired in March 2006 and was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, there was $3.1 million outstanding under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2006, our total-debt-to-total-capitalization ratio, as defined, was 63 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt to-total capitalization ratio.

*Uncommitted credit facilities*

In November 2005, AEM amended its $250 million uncommitted demand working capital credit facility to increase the amount of credit available from $250 million to a maximum of $580 million. In March 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 2007.

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

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At September 30, 2006, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.24 to 1.

At September 30, 2006, there were no borrowings outstanding under this credit facility. However, at September 30, 2006, AEM letters of credit totaling $96.1 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $53.9 million at September 30, 2006. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

We also have an unsecured short-term uncommitted credit line for $25 million that is used for working capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at September 30, 2006, but letters of credit reduced the amount available by $4.5 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a $100 million intercompany uncommitted demand credit facility with the Company which bears interest at the One Month LIBOR plus 2.75 percent. This facility has been approved by our state regulators through December 31, 2006. At September 30, 2006, there were no borrowings outstanding under this credit facility. In July 2006, this facility was renewed for one year with no material changes to its terms.

In addition, AEM has a $120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at the One Month LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's $580 million credit facility. At September 30, 2006, there were no borrowings outstanding under this credit facility. In July 2006, this facility was renewed for one year with no material changes to its terms.

***Debt Covenants***

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9.0 million. At September 30, 2006 approximately $203.3 million of retained earnings was unrestricted with respect to the payment of dividends.

As of September 30, 2006, a portion of the Mid-States Division utility plant assets, totaling $394.2 million, was subject to a lien under the Indenture of Mortgage of the Series P First Mortgage Bonds.

We were in compliance with all of our debt covenants as of September 30, 2006. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as both our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other triggering events.

Based on the borrowing rates currently available to us for debt with similar terms and remaining average maturities, the fair value of long-term debt at September 30, 2006 and 2005 is estimated, using discounted cash flow analysis, to be $2,053.9 million and $2,078.3 million.

Maturities of long-term debt at September 30, 2006 were as follows (in thousands):

| | |
|---|---|
| 2007 | $ 3,186 |
| 2008 | 303,831 |
| 2009 | 2,034 |
| 2010 | 401,381 |
| 2011 | 361,381 |
| Thereafter | 1,115,065 |
| | $2,186,878 |

## 7. Shareholders' Equity

***Stock Issuances***

During the years ended September 30, 2006, 2005 and 2004 we issued 1,200,115, 17,739,691 and 11,323,925 shares of common stock.

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

In October 2004, we completed the public offering of 16.1 million shares of our common stock including the underwriters' exercise of their overallotment option of 2.1 million shares. The offering was priced at $24.75 and generated net proceeds of approximately $381.6 million. We used the net proceeds from this offering, together with net proceeds of $235.7 million from a public offering we conducted in July 2004 and $1.39 billion received from the issuance of senior unsecured notes, to repay the $1.7 billion in outstanding commercial paper described in Note 3 and fund the remainder of the purchase price for the TXU Gas acquisition.

***Shareholder Rights Plan***

In November 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998. Each right entitles the registered holder to purchase from us a one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment. The description and terms of the rights are set forth in a rights agreement between us and the rights agent.

Subject to exceptions specified in the rights agreement, the rights will separate from our common stock and a distribution date will occur upon the earlier of:

- ten business days following a public announcement that a person or group of affiliated or associated persons has acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock, other than as a result of repurchases of stock by us or specified inadvertent actions by institutional or other shareholders;
- ten business days, or such later date as our Board of Directors shall determine, following the commencement of a tender offer or exchange offer that would result in a person or group having acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock; or
- ten business days after our Board of Directors shall declare any person to be an adverse person within the meaning of the rights plan.

The rights expire on May 10, 2008, unless extended prior thereto by our board of directors or earlier if redeemed by us. The rights will not have any voting rights. The exercise price payable and the number of shares of our common stock or other securities or property issuable upon exercise of the rights are subject to adjustment from time to time to prevent dilution. We issue rights when we issue our common stock until the rights have separated from the common stock. After the rights have separated from the common stock, we may issue additional rights if the board of directors deems such issuance to be necessary or appropriate. The rights have "anti-takeover" effects and may cause substantial dilution to a person or entity that attempts to acquire us on terms not approved by our board of directors except pursuant to an offer conditioned upon a substantial number of rights being acquired. The rights should not interfere with any merger or other business combination approved by our board of directors because, prior to the time that the rights become exercisable or transferable, we can redeem the rights at $.01 per right.

***Other Agreements***

In connection with our Mississippi Valley Gas Company acquisition in December 2002, we issued shares of common stock under an exemption from registration under the Securities Act of 1933, as amended. In the transaction, we entered into a registration rights agreement with the former stockholders of Mississippi Valley Gas Company that required us, on no more than two occasions, and with some limitations, to file a registration statement under the Securities Act within 60 days of their request for an offering designed to achieve a wide distribution of shares through underwriters selected by us. We also granted rights to these shareholders, subject to some limitations, to participate in future registered offerings of our securities until December 3, 2005. No registration rights issued to the former stockholders of MVG, as discussed above, were exercised prior to the expiration of the registration rights agreement on December 3, 2005. The former stockholders of MVG also agreed, for up to five years from the closing of the acquisition, or until December 3, 2007, and with some exceptions, not to sell or transfer shares representing more than 1 percent of our total outstanding voting securities to any person or group or any shares to a person or group who would hold more than 9.9 percent of our total outstanding voting securities after the sale or transfer. This restriction, and other agreed restrictions on the ability of these shareholders to acquire additional shares, participate in proxy solicitations or act to seek control, may be deemed to have an "anti-takeover" effect.

## 8. Stock and Other Compensation Plans

### *Stock-Based Compensation Plans*

*1998 Long-Term Incentive Plan*

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan, which became effective in October 1998 after approval by our shareholders. The Long-Term Incentive Plan is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to certain employees and non-employee directors of Atmos and its subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock. We are authorized to grant awards for up to a maximum of four million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2006, non-qualified stock options, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units had been issued under this plan, and 731,745 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years.

We used the Black-Scholes pricing model to estimate the fair value of each option granted with the following weighted average assumptions for 2006, 2005 and 2004:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Valuation Assumptions**[1] | | | |
| Expected Life *(years)*[2] | 7 | 7 | 7 |
| Interest rate[3] | 4.6% | 4.2% | 4.3% |
| Volatility[4] | 20.3% | 21.3% | 22.8% |
| Dividend yield | 4.8% | 4.8% | 4.8% |

(1) Beginning on the date of adoption of SFAS 123(R), forfeitures are estimated based on historical experience. Prior to the date of adoption, forfeitures were recorded as they occurred.

(2) The expected life of stock options is estimated based on historical experience.

(3) The interest rate is based on the U.S. Treasury constant maturity interest rate whose term is consistent with the expected life of the stock options.

(4) The volatility is estimated based on historical and current stock data for the Company.

A summary of activity for grants of stock options under the 1998 Long-Term Incentive Plan follows:

| | 2006 | | 2005 | | 2004 | |
|---|---|---|---|---|---|---|
| | Number of Options | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price |
| Outstanding at beginning of year | 964,704 | $22.20 | 1,492,177 | $22.10 | 1,827,310 | $21.91 |
| Granted | 93,196 | 26.19 | 23,432 | 25.95 | 8,118 | 24.44 |
| Exercised | (40,582) | 22.21 | (547,907) | 22.08 | (342,252) | 20.91 |
| Forfeited | (166) | 21.23 | (2,998) | 22.81 | (999) | 22.49 |
| Outstanding at end of year[1] | 1,017,152 | $22.57 | 964,704 | $22.20 | 1,492,177 | $22.10 |
| Exercisable at end of year[2] | 991,778 | $22.48 | 798,574 | $22.22 | 1,006,859 | $22.23 |

(1) The weighted-average remaining contractual life for outstanding options was 5.4 years, 6.0 years, and 7.0 years for fiscal years 2006, 2005 and 2004. The aggregate intrinsic value of outstanding options was $3.7 million, $3.5 million and $5.4 million for fiscal years 2006, 2005 and 2004.

(2) The weighted-average remaining contractual life for exercisable options was 5.3 years, 5.7 years, and 6.5 years for fiscal years 2006, 2005 and 2004. The aggregate intrinsic value of exercisable options was $3.6 million, $2.9 million and $3.7 million for fiscal years 2006, 2005 and 2004.

Information about outstanding and exercisable options under the 1998 Long-Term Incentive Plan, as of September 30, 2006, follows:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number of Options | Weighted Average Remaining Contractual Life (In Years) | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price |
| $15.65 to $20.24 | 64,833 | 3.4 | $15.66 | 64,833 | $15.66 |
| $20.25 to $22.99 | 547,414 | 5.8 | $21.87 | 547,414 | $21.87 |
| $23.00 to $26.19 | 404,905 | 5.1 | $24.62 | 379,531 | $24.53 |
| $15.65 to $26.19 | 1,017,152 | 5.4 | $22.57 | 991,778 | $22.48 |

The stock options had a weighted average fair value per share on the date of grant of $3.74 in 2006, $3.69 in 2005 and $3.82 in 2004. Net cash proceeds from the exercise of stock options during the years ended September 30, 2006, 2005 and 2004 were $0.9 million, $12.1 million and $7.2 million. The associated income tax benefit from stock options exercised during the years ended September 30, 2006, 2005 and 2004 were less than $0.1 million, $1.3 million and $0.6 million. The total intrinsic value of options exercised during the years ended September 30, 2006, 2005 and 2004 were less than $0.1 million, $2.0 million and $1.2 million.

As of September 30, 2006, there was less than $0.1 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a weighted-average period of 1.3 years.

### *Restricted Stock Plans*

As noted above, the 1998 Long-Term Incentive Plan provides for discretionary awards of restricted stock to help attract, retain and reward employees and non-employee directors of Atmos and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period. The following summarizes information regarding the restricted stock plan:

| | 2006 | | 2005 | | 2004 | |
|---|---|---|---|---|---|---|
| | Number of Restricted Shares | Weighted Average Grant-Date Fair Value | Number of Restricted Shares | Weighted Average Grant-Date Fair Value | Number of Restricted Shares | Weighted Average Grant-Date Fair Value |
| Nonvested at beginning of year | 592,490 | $25.32 | 345,519 | $23.72 | 107,837 | $21.19 |
| Granted | 440,016 | 26.80 | 294,834 | 26.78 | 240,686 | 24.78 |
| Vested | (265,546) | 24.42 | (36,106) | 21.97 | (2,175) | 15.65 |
| Forfeited | (20,184) | 26.95 | (11,757) | 24.70 | (829) | 23.83 |
| Nonvested at end of year | 746,776 | $26.49 | 592,490 | $25.32 | 345,519 | $23.72 |

As of September 30, 2006, there was $12.4 million of total unrecognized compensation cost related to nonvested restricted shares granted under the 1998 Long-Term Incentive Plan. That cost is expected to be recognized over a weighted-average period of 1.9 years. The fair value of restricted stock vested during the years ended September 30, 2006, 2005 and 2004 was $6.5 million, $0.8 million and less than $0.1 million.

***Other Plans***

*Direct Stock Purchase Plan*

We maintain a Direct Stock Purchase Plan which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. Through March 2004, participants were permitted to reinvest their cash dividends at a three percent discount from market prices. Effective April 2004, the three percent discount on reinvested dividends was eliminated and the minimum initial investment required to join the plan was increased to $1,250. Direct Stock Purchase Plan participants may purchase additional shares of Atmos common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

*Outside Directors Stock-For-Fee Plan*

In November 1994, the Board adopted the Outside Directors Stock-for-Fee Plan which was approved by the shareholders of Atmos in February 1995 and was amended and restated in November 1997. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

*Equity Incentive and Deferred Compensation Plan for Non-Employee Directors*

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by the shareholders of Atmos in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company in May 1990 and replaced the pension payable under the Company's Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

*Other Discretionary Compensation Plans*

We created the Variable Pay Plan in fiscal 1999 for our utility segment employees to give each employee an opportunity to share in the success of Atmos based on the achievement of key performance measures considered critical to achieving business objectives for a given year. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

We implemented the Annual Incentive Plan in October 2001 to give the employees in our nonutility segments an opportunity to share in the success of the nonutility operations. The plan is based upon the net earnings of the nonutility operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

## 9. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

### *Defined Benefit Plans*

*Employee Pension Plans*

As of September 30, 2006, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan, that was established effective January 1999 and covers substantially all employees of Atmos. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan will credit this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applies through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants fully vest in their account balances after five years of service and may choose to receive their account balances as a lump sum or an annuity.

The Union Plan is a defined benefit plan that covers substantially all full-time union employees in our Mississippi Division. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2006, we voluntarily contributed $2.9 million to the Union Plan. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities. We are not required to make a minimum funding contribution during fiscal 2007 nor do we anticipate making any voluntary contributions during fiscal 2007.

We manage the Master Trust's assets with the objective of achieving a rate of return net of inflation of approximately four percent per year. We make investment decisions and evaluate performance on a medium term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long term asset allocation policy.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2006 and 2005.

| Security Class | Targeted Allocation Range | Actual Allocation September 30 2006 | Actual Allocation September 30 2005 |
|---|---|---|---|
| Domestic equities | 35%-55% | 44.3% | 45.0% |
| International equities | 10%-20% | 15.6% | 17.9% |
| Fixed income | 10%-30% | 18.8% | 18.1% |
| Company stock | 0%-10% | 9.2% | 9.1% |
| Other assets | 5%-15% | 10.7% | 9.6% |
| Cash and equivalents | N/A | 1.4% | 0.3% |

At September 30, 2006 and 2005, the Plan held 1,169,700 shares of Atmos common stock, which represented 9.2 percent and 9.1 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.5 million during both fiscal 2006 and 2005.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a June 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of June 30, 2005, 2004 and 2003. These assumptions are presented in the following table:

| | Pension Liability | | Pension Cost | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 | 2004 |
| Discount rate | 6.30% | 5.00% | 5.00% | 6.25% | 6.00% |
| Rate of compensation increase | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Expected return on plan assets | 8.25% | 8.50% | 8.50% | 8.75% | 9.00% |

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2006 and 2005.

| | 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| **Accumulated benefit obligation** | $316,078 | $348,383 |
| **Change in projected benefit obligation:** | | |
| Benefit obligation at beginning of year | $359,924 | $312,997 |
| Service cost | 13,465 | 10,401 |
| Interest cost | 17,932 | 19,412 |
| Actuarial loss (gain) | (36,748) | 43,313 |
| Benefits paid | (28,109) | (26,199) |
| Benefit obligation at end of year | 326,464 | 359,924 |
| **Change in plan assets:** | | |
| Fair value of plan assets at beginning of year | 355,939 | 346,162 |
| Actual return on plan assets | 32,005 | 32,976 |
| Employer contributions | 2,879 | 3,000 |
| Benefits paid | (28,109) | (26,199) |
| Fair value of plan assets at end of year | 362,714 | 355,939 |
| **Reconciliation:** | | |
| Funded status | 36,250 | (3,985) |
| Unrecognized prior service cost | (4,980) | (5,939) |
| Unrecognized net loss | 65,646 | 119,270 |
| Net amount recognized | $ 96,916 | $109,346 |

Net periodic pension cost for the Plans for 2006, 2005 and 2004 is recorded as operating expense and included the following components:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (In thousands) | |
| Components of net periodic pension cost: | | | |
| Service cost | $ 13,465 | $ 10,401 | $ 7,696 |
| Interest cost | 17,932 | 19,412 | 19,691 |
| Expected return on assets | (25,598) | (27,541) | (30,097) |
| Amortization of prior service cost | (959) | (1,028) | (1,028) |
| Recognized actuarial loss | 10,469 | 6,276 | 6,555 |
| Net periodic pension cost | $ 15,309 | $ 7,520 | $ 2,817 |

*Supplemental Executive Benefits Plans*

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to the officers and certain other employees of Atmos. The Supplemental Plan was amended and restated in August 1998. In addition, in August 1998, we adopted the Performance-Based Supplemental Executive Benefits Plan which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of June 30, 2005, 2004 and 2003. These assumptions are presented in the following table:

| | Pension Liability | | Pension Cost | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 | 2004 |
| Discount rate | 6.30% | 5.00% | 5.00% | 6.25% | 6.00% |
| Rate of compensation increase | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2006 and 2005.

| | 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| **Accumulated benefit obligation** | $ 79,209 | $ 86,661 |
| **Change in projected benefit obligation:** | | |
| Benefit obligation at beginning of year | $ 97,941 | $ 73,998 |
| Service cost | 3,001 | 2,144 |
| Interest cost | 4,955 | 4,658 |
| Actuarial loss (gain) | (14,618) | 20,637 |
| Benefits paid | (3,780) | (3,496) |
| Benefit obligation at end of year | 87,499 | 97,941 |
| **Change in plan assets:** | | |
| Fair value of plan assets at beginning of year | — | — |
| Employer contribution | 3,780 | 3,496 |
| Benefits paid | (3,780) | (3,496) |
| Fair value of plan assets at end of year | — | — |
| **Reconciliation:** | | |
| Funded status | (87,499) | (97,941) |
| Unrecognized prior service cost | 1,684 | 2,706 |
| Unrecognized net loss | 22,927 | 40,334 |
| Accrued pension cost | $(62,888) | $(54,901) |

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

| | Cost | Unrealized Holding Gain | Market Value |
|---|---|---|---|
| | | (In thousands) | |
| **As of September 30, 2006:** | | | |
| Domestic equity mutual funds | $30,562 | $1,099 | $31,661 |
| Foreign equity mutual funds | 5,975 | 1,542 | 7,517 |
| | $36,537 | $2,641 | $39,178 |
| **As of September 30, 2005:** | | | |
| Domestic equity mutual funds | $28,902 | $ 897 | $29,799 |
| Foreign equity mutual funds | 5,133 | 328 | 5,461 |
| | $34,035 | $1,225 | $35,260 |

At September 30, 2006, we maintained investments in one domestic equity mutual fund and one domestic bond fund that were in unrealized loss positions as of September 30, 2006. Information concerning unrealized losses for our supplemental plan assets follows:

| | Less Than 12 Months | | 12 Months or More | |
|---|---|---|---|---|
| | Fair Value | Unrealized Loss | Fair Value | Unrealized Loss |
| | (In thousands) | | | |
| Domestic equity mutual funds | $19,963 | $773 | $— | $— |

Because these funds are only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold these investments, the short-term nature of the impairment as of September 30, 2006 and our ability to direct the source of the payments in order to maximize the life of the portfolio, the improved investment returns in the last year and the fact that these funds continue to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary.

Net periodic pension cost for the supplemental plans for 2006, 2005 and 2004 is recorded as operating expense and included the following components:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands) | | |
| Components of net periodic pension cost: | | | |
| Service cost | $ 3,001 | $2,144 | $2,037 |
| Interest cost | 4,955 | 4,658 | 4,324 |
| Amortization of transition asset | — | 4 | 96 |
| Amortization of prior service cost | 1,022 | 1,022 | 1,022 |
| Recognized actuarial loss | 2,789 | 1,290 | 1,516 |
| Net periodic pension cost | $11,767 | $9,118 | $8,995 |

*Supplemental Disclosures For Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets*

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2005 the accumulated benefit obligation for the MVG plan exceeded the fair value of plan assets. For fiscal 2006 and 2005 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

| | Employee Pension Plans | Supplemental Plans | |
|---|---|---|---|
| | 2005 | 2006 | 2005 |
| | (In thousands) | | |
| Projected Benefit Obligation | $13,550 | $87,499 | $97,941 |
| Accumulated Benefit Obligation | 10,738 | 79,209 | 86,661 |
| Fair Value of Plan Assets | 6,465 | — | — |

*Estimated Future Benefit Payments*

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

| | Pension Plans | Supplemental Plans |
|---|---|---|
| | (In thousands) | |
| 2007 | $ 32,119 | $ 3,729 |
| 2008 | 27,923 | 4,242 |
| 2009 | 28,588 | 4,512 |
| 2010 | 29,811 | 5,262 |
| 2011 | 29,399 | 5,287 |
| 2012-2016 | 122,553 | 29,913 |

***Postretirement Benefits***

At September 30, 2006, we sponsored the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). Effective December 31, 2004, the Atmos Energy Corporation Retiree Welfare Benefits Plan for Certain MVG Non-Union Employees and the Atmos Energy Corporation Retiree Welfare Benefits Plan for MVG Union Employees merged into the Atmos Retiree Medical Plan.

This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent of this cost.

On October 1, 2004, in connection with the acquisition of TXU Gas, we transitioned certain employees from TXU Gas to Atmos Energy Corporation. Although we did not assume the existing employee benefit liabilities or plans of TXU Gas, we received a credit of $18.9 million against the purchase price to permit us to provide partial past service credits for retiree medical benefits under the Atmos Retiree Medical Plan. The $18.9 million credit approximated the actuarially determined present value of the accumulated benefits related to the past service of the transitioned employees on the acquisition date.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $11.4 million to our postretirement benefits plans during fiscal 2007.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plans to ensure the assets funding the postretirement benefit plans are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plans.

We currently invest the assets funding our postretirement benefit plans in money market funds, equity mutual funds, fixed income funds and a balanced fund. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2006 and 2005.

| | Actual Allocation September 30 | |
|---|---|---|
| Security Class | 2006 | 2005 |
| Diversified investment fund[1] | 100% | 97.2% |
| Cash and cash equivalents | — | 2.8% |

[1] This fund invests in a diversified portfolio of common stocks, preferred stocks and fixed income securities. It may invest up to 75 percent of assets in common stocks and convertible securities.

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of June 30, 2005, 2004 and 2003. The assumptions are presented in the following table:

| | Postretirement Liability | | Postretirement Cost | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 | 2004 |
| Discount rate | 6.30% | 5.00% | 5.00% | 6.25% | 6.19% |
| Expected return on plan assets | 5.20% | 5.30% | 5.30% | 5.30% | 5.30% |
| Initial trend rate | 8.00% | 9.00% | 9.00% | 10.00% | 9.00% |
| Ultimate trend rate | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Ultimate trend reached in | 2010 | 2010 | 2010 | 2010 | 2008 |

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2006 and 2005.

| | 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| **Change in benefit obligation:** | | |
| Benefit obligation at beginning of year | $ 170,930 | $ 125,189 |
| Service cost | 13,083 | 9,968 |
| Interest cost | 8,840 | 9,369 |
| Plan participants' contributions | 1,340 | 2,131 |
| Actuarial loss (gain) | (22,657) | 16,449 |
| Acquisition | — | 18,878 |
| Benefits paid | (10,695) | (11,054) |
| Subsidy payments | 60 | — |
| Benefit obligation at end of year | 160,901 | 170,930 |
| **Change in plan assets:** | | |
| Fair value of plan assets at beginning of year | 39,843 | 36,408 |
| Actual return on plan assets | 3,703 | 2,365 |
| Employer contributions | 10,609 | 9,993 |
| Plan participants' contributions | 1,340 | 2,131 |
| Benefits paid | (10,695) | (11,054) |
| Fair value of plan assets at end of year | 44,800 | 39,843 |
| **Reconciliation:** | | |
| Funded status | (116,101) | (131,087) |
| Unrecognized transition obligation | 11,154 | 12,665 |
| Unrecognized prior service cost | 33 | 394 |
| Unrecognized net loss | 3,060 | 28,513 |
| Accrued postretirement cost | $(101,854) | $ (89,515) |

Net periodic postretirement cost for 2006, 2005 and 2004 is recorded as operating expense and included the components presented below. The 2006, 2005 and 2004 amounts reflect the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) beginning in the second quarter of fiscal 2004 as the plan is considered "actuarially equivalent" to Medicare Part D.

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (In thousands) | | |
| Components of net periodic postretirement cost: | | | |
| Service cost | $13,083 | $ 9,968 | $ 5,941 |
| Interest cost | 8,840 | 9,369 | 7,355 |
| Expected return on assets | (2,187) | (2,070) | (1,523) |
| Amortization of transition obligation | 1,511 | 1,511 | 1,511 |
| Amortization of prior service cost | 361 | 386 | 386 |
| Recognized actuarial loss | 1,280 | 622 | 635 |
| Net periodic postretirement cost | $22,888 | $19,786 | $14,305 |

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

| | 1-Percentage Point Increase | 1-Percentage Point Decrease |
|---|---|---|
| | (In thousands) | |
| Effect on total service and interest cost components | $ 3,782 | $ (3,064) |
| Effect on postretirement benefit obligation | $17,678 | $(14,974) |

We are currently recovering other postretirement benefits costs through our regulated rates under SFAS 106 accrual accounting in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Mid-States Division and our Mississippi Division or have been included in a rate case and not disallowed. Management believes that accrual accounting in accordance with SFAS 106 is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

*Estimated Future Benefit Payments*

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

| | Company Payments | Retiree Payments | Subsidy Payments | Total Postretirement Benefits |
|---|---|---|---|---|
| | | (In thousands) | | |
| 2007 | $11,408 | $ 2,249 | $127 | $ 13,784 |
| 2008 | 10,180 | 2,574 | 32 | 12,786 |
| 2009 | 11,404 | 2,743 | — | 14,147 |
| 2010 | 12,520 | 3,015 | — | 15,535 |
| 2011 | 13,621 | 3,278 | — | 16,899 |
| 2012-2016 | 86,065 | 20,698 | — | 106,763 |

### *Defined Contribution Plans*

As of September 30, 2006, we maintained two defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan) and the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan).

The Retirement Savings Plan covers substantially all employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in Atmos common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

The Union 401K Plan covers substantially all Mississippi Division employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (the Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the Union 401K plan on the date of union employment. We match 50 percent of a participant's contribution, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to our defined contribution plans are expensed as incurred and amounted to \$7.0 million, \$5.7 million, and \$4.6 million for 2006, 2005 and 2004. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for 2006, 2005 or 2004. At September 30, 2006 and 2005, the Retirement Savings Plan held 3.2 percent and 3.1 percent of our outstanding common stock.

## 10. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

### *Accounts receivable*

Accounts receivable was comprised of the following at September 30, 2006 and 2005:

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Billed accounts receivable | $321,279 | $381,469 |
| Unbilled revenue | 44,607 | 62,337 |
| Other accounts receivable | 22,429 | 26,120 |
| Total accounts receivable | 388,315 | 469,926 |
| Less: allowance for doubtful accounts | (13,686) | (15,613) |
| Net accounts receivable | $374,629 | $454,313 |

### *Other current assets*

Other current assets as of September 30, 2006 and 2005 were comprised of the following accounts.

| | September 30 2006 | September 30 2005 |
|---|---|---|
| | (In thousands) | |
| Assets from risk management activities | $ 12,553 | $107,913 |
| Deferred gas cost | 44,992 | 38,173 |
| Taxes receivable | 56,034 | — |
| Current deferred tax asset | 18,943 | 67,365 |
| Prepaid expenses | 16,379 | 13,334 |
| Current portion of leased assets receivable | 2,973 | 2,973 |
| Materials and supplies | 6,088 | 7,502 |
| Other | 11,990 | 978 |
| Total | $169,952 | $238,238 |

### *Property, plant and equipment*

Property, plant and equipment was comprised of the following as of September 30, 2006 and 2005:

| | September 30 2006 | September 30 2005 |
|---|---|---|
| | (In thousands) | |
| Production plant | $ 12,563 | $ 19,401 |
| Storage plant | 118,902 | 116,708 |
| Transmission plant | 863,882 | 753,499 |
| Distribution plant | 3,404,220 | 3,164,316 |
| General plant | 541,852 | 502,189 |
| Intangible plant | 85,059 | 75,571 |
| | 5,026,478 | 4,631,684 |
| Construction in progress | 74,830 | 133,926 |
| | 5,101,308 | 4,765,610 |
| Less: accumulated depreciation and amortization | (1,472,152) | (1,391,243) |
| Net property, plant and equipment | $ 3,629,156 | $ 3,374,367 |

### *Deferred charges and other assets*

Deferred charges and other assets as of September 30, 2006 and 2005 were comprised of the following accounts.

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Pension plan assets in excess of plan obligations | $ 96,916 | $109,346 |
| Marketable securities | 39,178 | 35,260 |
| Long-term receivable on leased assets | 16,440 | 19,413 |
| Regulatory assets | 30,823 | 37,844 |
| Deferred financing costs | 42,673 | 47,792 |
| Assets from risk management activities | 6,186 | 735 |
| Other | 2,109 | 26,553 |
| Total | $234,325 | $276,943 |

### *Other current liabilities*

Other current liabilities as of September 30, 2006 and 2005 were comprised of the following accounts.

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Customer deposits | $102,555 | $ 89,918 |
| Accrued employee costs | 27,276 | 26,409 |
| Deferred gas costs | 68,959 | 134,048 |
| Accrued interest | 54,892 | 53,675 |
| Liabilities from risk management activities | 30,669 | 61,920 |
| Taxes payable | 50,673 | 66,083 |
| Post-retirement obligations | 8,850 | 5,300 |
| Regulatory cost of removal accrual | 15,114 | 11,565 |
| Other | 29,463 | 54,450 |
| Total | $388,451 | $503,368 |

### *Deferred credits and other liabilities*

Deferred credits and other liabilities as of September 30, 2006 and 2005 were comprised of the following accounts.

| | September 30 | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Post-retirement obligations | $ 93,004 | $ 84,215 |
| Nonqualified retirement plan obligation | 62,888 | 54,901 |
| Customer advances for construction | 17,481 | 18,872 |
| Liabilities from risk management activities | 276 | 15,316 |
| Deferred revenue | 4,049 | 5,488 |
| Regulatory liabilities | 10,825 | 8,084 |
| Asset retirement obligation | 15,070 | — |
| Other | 785 | 12,739 |
| Total | $204,378 | $199,615 |

## 11. Earnings Per Share

Basic and diluted earnings per share for the years ended September 30 are calculated as follows:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands, except per share data) | | |
| Net income | $147,737 | $135,785 | $86,227 |
| Denominator for basic income per share — weighted average common shares | 80,731 | 78,508 | 54,021 |
| Effect of dilutive securities: | | | |
| Restricted and other shares | 551 | 360 | 281 |
| Stock options | 108 | 144 | 114 |
| Denominator for diluted income per share — weighted average common shares | 81,390 | 79,012 | 54,416 |
| Net income per share — basic | $ 1.83 | $ 1.73 | $ 1.60 |
| Net income per share — diluted | $ 1.82 | $ 1.72 | $ 1.58 |

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the year ended September 30, 2006 and 2005. There were approximately 3,000 out-of-the-money options excluded from the computation of diluted earnings per share for the year ended September 30, 2004 as their exercise price was greater than the average market price of the common stock during that period.

## 12. Income Taxes

The components of income tax expense from continuing operations for 2006, 2005 and 2004 were as follows:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | | (In thousands) | |
| Current | | | |
| Federal | $ 838 | $61,508 | $ 9,003 |
| State | 2,623 | 8,569 | 2,021 |
| Deferred | | | |
| Federal | 77,154 | 11,453 | 35,970 |
| State | 9,024 | 1,217 | 5,079 |
| Investment tax credits | (486) | (514) | (535) |
| | $89,153 | $82,233 | $51,538 |

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2006, 2005 and 2004 are set forth below:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | | (In thousands) | |
| Tax at statutory rate of 35% | $82,912 | $76,306 | $48,218 |
| Common stock dividends deductible for tax reporting | (1,180) | (1,088) | (985) |
| State taxes (net of federal benefit) | 7,570 | 6,361 | 4,615 |
| Other, net | (149) | 654 | (310) |
| Income tax expense | $89,153 | $82,233 | $51,538 |

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that give rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2006 and 2005 are presented below:

| | 2006 | 2005 |
|---|---|---|
| | (In thousands) | |
| **Deferred tax assets:** | | |
| Costs expensed for book purposes and capitalized for tax purposes | $ 6,469 | $ 1,299 |
| Accruals not currently deductible for tax purposes | 7,709 | 13,319 |
| Customer advances | 6,643 | 8,455 |
| Nonqualified benefit plans | 26,337 | 24,869 |
| Postretirement benefits | 37,558 | 33,176 |
| Treasury lock agreement | 12,589 | 14,698 |
| Unamortized investment tax credit | 680 | 864 |
| Regulatory liabilities | 1,460 | 9,836 |
| Tax net operating loss and credit carryforwards | 5,623 | 855 |
| Gas cost adjustments | 19,434 | 36,432 |
| Other, net | 4,525 | 9,781 |
| Total deferred tax assets | 129,027 | 153,584 |
| **Deferred tax liabilities:** | | |
| Difference in net book value and net tax value of assets | (364,438) | (317,834) |
| Pension funding | (37,188) | (42,597) |
| Regulatory assets | (1,695) | (13,021) |
| Cost capitalized for book purposes and expensed for tax purposes | (1,618) | (2,739) |
| Difference between book and tax on mark to market accounting | (9,536) | (82) |
| Other, net | (1,781) | (2,153) |
| Total deferred tax liabilities | (416,256) | (378,426) |
| Net deferred tax liabilities | $(287,229) | $(224,842) |
| SFAS No. 109 deferred credits for rate regulated entities | $ 2,687 | $ 2,833 |

We have tax carryforwards amounting to $5.6 million. The tax carryforwards include net operating losses for federal purposes amounting to $4.3 million and state net operating losses amounting to $1.3 million. The federal net operating loss carryforwards will expire in 2026. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2011 and 2026.

The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns. We believe all material tax items which relate to the years under audit have been properly accrued.

## 13. Commitments and Contingencies

### *Litigation*

*Colorado-Kansas Division*

We are a defendant in a lawsuit originally filed by Quinque Operating Company, Tom Boles and Robert Ditto in September 1999 in the District Court of Stevens County, Kansas against more than 200 companies in the natural gas industry. The plaintiffs, who purport to represent a class of royalty owners, allege that the defendants have underpaid royalties on gas taken from wells situated on non-federal and non-Indian lands in Kansas, predicated upon allegations that the defendants' gas measurements were inaccurate. The plaintiffs have not specifically alleged an amount of damages. We are also a defendant, along with over 50 other companies in the natural gas industry, in another proposed class action lawsuit filed in the same court by Will Price, Tom Boles and The Cooper Clarke Foundation in May 2003 involving similar allegations. We believe that the plaintiffs' claims are lacking in merit and we intend to vigorously defend these actions. While the results cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial conditions, results of operations or net cash flows. We were also a defendant in another lawsuit entitled *In Re Natural Gas Royalties Qui Tam Litigation*, involving similar allegations filed in June 1997 in the United States District Court for the District of Colorado, which was later transferred to the United States District Court for the District of Wyoming, where it was consolidated with approximately 50 additional lawsuits in October 1999. On October 20, 2006, the District Court granted the defendants' motion to dismiss this lawsuit for lack of subject matter jurisdiction.

*United Cities Propane Gas, Inc.*

United Cities Propane Gas, Inc., one of our wholly-owned subsidiaries, was a party to an action filed in June 2000 that was pending in the Circuit Court of Sevier County, Tennessee. The plaintiffs' claims arose out of injuries alleged to have been caused by a low-level propane explosion. The plaintiffs were seeking to recover damages of $13.0 million. The case was settled on November 14, 2006. As the settlement amount was fully covered by insurance, the settlement did not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a party to other litigation and claims that arose in the ordinary course of our business, including certain litigation and claims that arose in the ordinary course of the business of TXU Gas Company, the natural gas distribution and pipeline operations we acquired on October 1, 2004. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

### *Environmental Matters*

*Former Manufactured Gas Plant Sites*

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

United Cities Gas Company and the Tennessee Department of Environment and Conservation (TDEC) entered into a consent order effective in January 1997, to facilitate the investigation, removal and remediation of the Johnson City site. Prior to our merger with United Cities Gas Company in July 1997, United Cities Gas

Company began the implementation of the consent order in the first quarter of fiscal 1997, which will continue for the foreseeable future. The investigative phase of the work at the site has been completed, and an interim removal action was completed in June 2001. We installed four groundwater monitoring wells at the site in 2002 and have submitted the analytical results to the TDEC. We completed a risk assessment report that has been approved by the TDEC as well as a feasibility study for this site, which was submitted to the TDEC in October 2003. The feasibility study recommends a remedial action that will limit the use of and access to the impacted soil, cap the site with the addition of a clay fill and geosynthetic liner and groundwater monitoring for a period of up to 30 years. The feasibility study was approved by the TDEC in February 2005. The estimated cost of the remedial action is $1.5 million, which is comprised primarily of operating and maintenance costs that would be associated with a groundwater monitoring project. In January 2006, the TDEC issued a Record of Decision approving the remedial action recommended in the feasibility study. The Tennessee Regulatory Authority granted us permission to defer, until our next rate case in Tennessee, all costs incurred in Tennessee in connection with state and federally mandated environmental control requirements.

In March 2002, the TDEC contacted us about conducting an investigation at a former manufactured gas plant located in Bristol, Tennessee. We agreed to perform a preliminary investigation at the site, which we completed in June 2002. The investigation identified manufactured gas plant residual materials in the soil beneath the site, and we have proposed performing a focused removal action to remove any such residuals. The TDEC requested that the focused removal action be conducted pursuant to a voluntary agreement. In April 2004, we entered into a voluntary consent agreement with the TDEC for the performance of the removal action and the removal action was completed in November 2004. In September 2005, we filed site use limitations on the property in the local property records, including restrictions on the use of the site to commercial and industrial purposes and a prohibition of the use of groundwater for use as drinking water were filed. In February 2006, we received a Completion Letter from the TDEC informing us that no further action is required at this site pursuant to the voluntary consent agreement with the TDEC.

In July 1998, we entered into an Abatement Order on Consent with the Missouri Department of Natural Resources to address the former manufactured gas plant located in Hannibal, Missouri. We agreed to perform a removal action and a subsequent site evaluation and to reimburse the response costs incurred by the state of Missouri in connection with the property. The removal action was conducted and completed in August 1998, and the site-evaluation field work was conducted in August 1999. A risk assessment for the site has been approved by the Missouri Department of Natural Resources. In preparation for the risk assessment, we executed and recorded certain site-use limitations, including restricting use of the site to commercial and industrial purposes and prohibiting the withdrawal of groundwater for use as drinking water. In addition, we have installed a geosynthetic liner over the surface of the site.

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

As of September 30, 2006, we had incurred costs of approximately $2.3 million for the investigations of the Johnson City and Bristol, Tennessee, and Hannibal, Missouri sites.

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

*Purchase Commitments*

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2006, AEM was committed to purchase 61.7 Bcf within one year, 51.2 Bcf within one to three years and 0.8 Bcf after three years under indexed contracts. AEM is committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from \$3.40 to \$12.00. Purchases under these contracts totaled \$2,124.3 million, \$1,421.2 million and \$1,252.2 million for 2006, 2005 and 2004.

Our utility 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 prices. The estimated commitments under these contracts as of September 30, 2006 are as follows (in thousands):

| | |
|---|---|
| 2007 | \$560,461 |
| 2008 | 101,702 |
| 2009 | 9,091 |
| 2010 | 8,518 |
| 2011 | 8,517 |
| Thereafter | 19,928 |
| | \$708,217 |

## 14. Leases

*Leasing Operations*

Atmos Power Systems, Inc. constructs electric peaking power-generating plants and associated facilities and enters into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2006 and 2005, we had receivables of \$19.4 million and \$22.4 million and recognized income of \$1.7 million, \$1.6 million and \$1.9 million for fiscal years 2006, 2005 and 2004. The future minimum lease payments to be received for each of the five succeeding years are as follows:

| | Minimum Lease Receipts |
|---|---|
| | (In thousands) |
| 2007 | \$ 2,973 |
| 2008 | 2,973 |
| 2009 | 2,973 |
| 2010 | 2,973 |
| 2011 | 2,973 |
| Thereafter | 4,548 |
| Total minimum lease receipts | \$19,413 |

*Capital and Operating Leases*

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 20 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $5.8 million at September 30, 2006 and 2005. Accumulated depreciation for these capital leases totaled $4.2 million and $3.8 million at September 30, 2006 and 2005. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2006 were as follows:

| | Capital Leases | Operating Leases |
|---|---|---|
| | (In thousands) | |
| 2007 | $ 433 | $ 15,959 |
| 2008 | 362 | 15,463 |
| 2009 | 311 | 14,694 |
| 2010 | 291 | 13,502 |
| 2011 | 186 | 13,410 |
| Thereafter | 1,194 | 103,778 |
| Total minimum lease payments | 2,777 | $176,806 |
| Less amount representing interest | 1,205 | |
| Present value of net minimum lease payments | $1,572 | |

Consolidated lease and rental expense amounted to $11.4 million, $9.5 million and $8.1 million for fiscal 2006, 2005 and 2004.

## 15. Concentration of Credit Risk

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

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

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

AEM's estimated credit exposure is monitored in terms of the percentage of its customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2006 and 2005.

| | September 30, 2006 | September 30, 2005 |
|---|---|---|
| Investment grade | 40% | 49% |
| Non-investment grade | 60% | 51% |
| Total | 100% | 100% |

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of September 30, 2006. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's Rating Group; or Baa3, assigned by Moody's Investor Service. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

| | Utility Segment[1] | Natural Gas Marketing Segment | Consolidated |
|---|---|---|---|
| | | (In thousands) | |
| Investment grade counterparties | $— | $16,001 | $16,001 |
| Non-investment grade counterparties | — | 2,738 | 2,738 |
| | $— | $18,739 | $18,739 |

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

## 16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for 2006, 2005 and 2004 are presented below.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | | (In thousands) | |
| Cash paid for interest | $149,031 | $103,418 | $65,700 |
| Cash paid for income taxes | $ 77,265 | $ 51,490 | $ 1,677 |

There were no significant noncash investing and financing transactions during fiscal 2006, 2005 and 2004. All cash flows and non cash activities related to our commodity derivatives are considered as operating activities.

## 17. Segment Information

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

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

Our operations are divided into four segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Summarized income statements and capital expenditures by segment are shown in the following tables.

| | Year Ended September 30, 2006 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | | | (In thousands) | | | |
| Operating revenues from external parties | $3,649,851 | $2,418,856 | $ 81,857 | $1,799 | $ — | $6,152,363 |
| Intersegment revenues | 740 | 737,668 | 78,710 | 4,099 | (821,217) | — |
| | 3,650,591 | 3,156,524 | 160,567 | 5,898 | (821,217) | 6,152,363 |
| Purchased gas cost | 2,725,534 | 3,025,897 | 838 | — | (816,476) | 4,935,793 |
| Gross profit | 925,057 | 130,627 | 159,729 | 5,898 | (4,741) | 1,216,570 |
| Operating expenses | | | | | | |
| Operation and maintenance | 357,519 | 22,223 | 53,641 | 5,013 | (4,978) | 433,418 |
| Depreciation and amortization | 164,493 | 1,834 | 19,166 | 103 | — | 185,596 |
| Taxes, other than income | 178,204 | 4,335 | 9,064 | 390 | — | 191,993 |
| Impairment of long-lived assets | 22,947 | — | — | — | — | 22,947 |
| Total operating expenses | 723,163 | 28,392 | 81,871 | 5,506 | (4,978) | 833,954 |
| Operating income | 201,894 | 102,235 | 77,858 | 392 | 237 | 382,616 |
| Miscellaneous income | 9,506 | 2,598 | 2,554 | 4,151 | (17,928) | 881 |
| Interest charges | 126,489 | 8,510 | 25,331 | 3,968 | (17,691) | 146,607 |
| Income before income taxes | 84,911 | 96,323 | 55,081 | 575 | — | 236,890 |
| Income tax expense | 31,909 | 37,757 | 19,457 | 30 | — | 89,153 |
| Net income | $ 53,002 | $ 58,566 | $ 35,624 | $ 545 | $ — | $ 147,737 |
| Capital expenditures | $ 307,742 | $ 909 | $116,673 | $ — | $ — | $ 425,324 |

| | Year Ended September 30, 2005 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | (In thousands) | | | | | |
| Operating revenues from external parties | $3,102,041 | $1,783,926 | $ 73,880 | $2,026 | $ — | $4,961,873 |
| Intersegment revenues | 1,099 | 322,352 | 79,409 | 3,276 | (406,136) | — |
| | 3,103,140 | 2,106,278 | 153,289 | 5,302 | (406,136) | 4,961,873 |
| Purchased gas cost | 2,195,774 | 2,044,305 | 6,811 | — | (402,654) | 3,844,236 |
| Gross profit | 907,366 | 61,973 | 146,478 | 5,302 | (3,482) | 1,117,637 |
| Operating expenses | | | | | | |
| Operation and maintenance | 346,594 | 18,444 | 50,773 | 4,153 | (3,683) | 416,281 |
| Depreciation and amortization | 159,497 | 1,896 | 16,504 | 108 | — | 178,005 |
| Taxes, other than income | 164,910 | 648 | 8,915 | 223 | — | 174,696 |
| Total operating expenses | 671,001 | 20,988 | 76,192 | 4,484 | (3,683) | 768,982 |
| Operating income | 236,365 | 40,985 | 70,286 | 818 | 201 | 348,655 |
| Miscellaneous income | 6,776 | 771 | 2,030 | 2,575 | (10,131) | 2,021 |
| Interest charges | 112,382 | 3,405 | 24,579 | 2,222 | (9,930) | 132,658 |
| Income before income taxes | 130,759 | 38,351 | 47,737 | 1,171 | — | 218,018 |
| Income tax expense | 49,642 | 14,947 | 17,138 | 506 | — | 82,233 |
| Net income | $ 81,117 | $ 23,404 | $ 30,599 | $ 665 | $ — | $ 135,785 |
| Capital expenditures | $ 300,574 | $ 649 | $ 31,960 | $ — | $ — | $ 333,183 |

| | Year Ended September 30, 2004 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | (In thousands) | | | | | |
| Operating revenues from external parties | $1,636,636 | $1,279,424 | $ 1,617 | $2,360 | $ — | $2,920,037 |
| Intersegment revenues | 1,092 | 339,178 | 18,141 | 1,033 | (359,444) | — |
| | 1,637,728 | 1,618,602 | 19,758 | 3,393 | (359,444) | 2,920,037 |
| Purchased gas cost | 1,134,594 | 1,571,971 | 9,383 | — | (358,102) | 2,357,846 |
| Gross profit | 503,134 | 46,631 | 10,375 | 3,393 | (1,342) | 562,191 |
| Operating expenses | | | | | | |
| Operation and maintenance | 195,471 | 15,692 | 2,533 | 2,150 | (1,376) | 214,470 |
| Depreciation and amortization | 92,954 | 2,089 | 1,488 | 116 | — | 96,647 |
| Taxes, other than income | 54,819 | 1,124 | 1,061 | 375 | — | 57,379 |
| Total operating expenses | 343,244 | 18,905 | 5,082 | 2,641 | (1,376) | 368,496 |
| Operating income | 159,890 | 27,726 | 5,293 | 752 | 34 | 193,695 |
| Miscellaneous income | 5,847 | 843 | 289 | 8,290 | (5,762) | 9,507 |
| Interest charges | 65,399 | 2,711 | 1,053 | 2,002 | (5,728) | 65,437 |
| Income before income taxes | 100,338 | 25,858 | 4,529 | 7,040 | — | 137,765 |
| Income tax expense | 37,242 | 9,225 | 1,762 | 3,309 | — | 51,538 |
| Net income | $ 63,096 | $ 16,633 | $ 2,767 | $3,731 | $ — | $ 86,227 |
| Capital expenditures | $ 189,291 | $ 520 | $ 474 | $ — | $ — | $ 190,285 |

The following table summarizes our revenues by products and services for the year ended September 30.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | | (In thousands) | |
| Utility revenues: | | | |
| Gas sales revenues: | | | |
| Residential | $2,068,736 | $1,791,172 | $ 923,773 |
| Commercial | 1,061,783 | 869,722 | 400,704 |
| Industrial | 276,186 | 229,649 | 155,336 |
| Agricultural | 40,664 | 27,889 | 31,851 |
| Public authority and other | 103,936 | 86,853 | 77,178 |
| Total gas sales revenues | 3,551,305 | 3,005,285 | 1,588,842 |
| Transportation revenues | 61,475 | 58,897 | 30,622 |
| Other gas revenues | 37,071 | 37,859 | 17,172 |
| Total utility revenues | 3,649,851 | 3,102,041 | 1,636,636 |
| Natural gas marketing revenues | 2,418,856 | 1,783,926 | 1,279,424 |
| Pipeline and storage revenues | 81,857 | 73,880 | 1,617 |
| Other nonutility revenues | 1,799 | 2,026 | 2,360 |
| Total operating revenues | $6,152,363 | $4,961,873 | $2,920,037 |

## ATMOS ENERGY CORPORATION

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Balance sheet information at September 30, 2006 and 2005 by segment is presented in the following tables:

| | September 30, 2006 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | (In thousands) | | | | | |
| ASSETS | | | | | | |
| Property, plant and equipment, net | $3,083,301 | $ 7,531 | $537,028 | $ 1,296 | $ — | $3,629,156 |
| Investment in subsidiaries | 281,143 | (2,155) | — | — | (278,988) | — |
| Current assets | | | | | | |
| Cash and cash equivalents | 8,738 | 45,481 | — | 21,596 | — | 75,815 |
| Cash held on deposit in margin account | — | 35,647 | — | — | — | 35,647 |
| Assets from risk management activities | — | 13,164 | 19,040 | — | (19,651) | 12,553 |
| Other current assets | 714,472 | 261,435 | 26,325 | 8,119 | (16,821) | 993,530 |
| Intercompany receivables | 602,809 | — | — | — | (602,809) | — |
| Total current assets | 1,326,019 | 355,727 | 45,365 | 29,715 | (639,281) | 1,117,545 |
| Intangible assets | — | 3,152 | — | — | — | 3,152 |
| Goodwill | 567,221 | 24,282 | 143,866 | — | — | 735,369 |
| Noncurrent assets from risk management activities | — | 6,190 | 5 | — | (9) | 6,186 |
| Deferred charges and other assets | 204,617 | 1,315 | 5,301 | 16,906 | — | 228,139 |
| | $5,462,301 | $396,042 | $731,565 | $47,917 | $(918,278) | $5,719,547 |
| CAPITALIZATION AND LIABILITIES | | | | | | |
| Shareholders' equity | $1,648,098 | $139,863 | $107,640 | $33,640 | $(281,143) | $1,648,098 |
| Long-term debt | 2,176,473 | — | — | 3,889 | — | 2,180,362 |
| Total capitalization | 3,824,571 | 139,863 | 107,640 | 37,529 | (281,143) | 3,828,460 |
| Current liabilities | | | | | | |
| Current maturities of long-term debt | 1,250 | — | — | 1,936 | — | 3,186 |
| Short-term debt | 382,416 | — | — | — | — | 382,416 |
| Liabilities from risk management activities | 27,209 | 22,500 | 531 | — | (19,571) | 30,669 |
| Other current liabilities | 473,101 | 183,077 | 61,458 | — | (14,746) | 702,890 |
| Intercompany payables | — | 75,665 | 525,895 | 1,249 | (602,809) | — |
| Total current liabilities | 883,976 | 281,242 | 587,884 | 3,185 | (637,126) | 1,119,161 |
| Deferred income taxes | 297,821 | (25,777) | 31,927 | 2,201 | — | 306,172 |
| Noncurrent liabilities from risk management activities | — | 280 | 5 | — | (9) | 276 |
| Regulatory cost of removal obligation | 261,376 | — | — | — | — | 261,376 |
| Deferred credits and other liabilities | 194,557 | 434 | 4,109 | 5,002 | — | 204,102 |
| | $5,462,301 | $396,042 | $731,565 | $47,917 | $(918,278) | $5,719,547 |

| | September 30, 2005 | | | | | |
|---|---|---|---|---|---|---|
| | Utility | Natural Gas Marketing | Pipeline and Storage | Other Nonutility | Eliminations | Consolidated |
| | (In thousands) | | | | | |
| ASSETS | | | | | | |
| Property, plant and equipment, net | $2,926,096 | $ 7,278 | $439,574 | $ 1,419 | $ — | $3,374,367 |
| Investment in subsidiaries | 231,342 | (1,896) | — | — | (229,446) | — |
| Current assets | | | | | | |
| Cash and cash equivalents | 10,663 | 28,949 | — | 504 | — | 40,116 |
| Cash held on deposit in margin account | 4,170 | 76,786 | — | — | — | 80,956 |
| Assets from risk management activities | 93,310 | 39,528 | 1,739 | — | (26,664) | 107,913 |
| Other current assets | 666,081 | 421,777 | 36,208 | 63,820 | (152,441) | 1,035,445 |
| Intercompany receivables | 505,728 | — | — | 20,133 | (525,861) | — |
| Total current assets | 1,279,952 | 567,040 | 37,947 | 84,457 | (704,966) | 1,264,430 |
| Intangible assets | — | 3,507 | — | — | — | 3,507 |
| Goodwill | 566,800 | 24,282 | 143,198 | — | — | 734,280 |
| Noncurrent assets from risk management activities | — | 2,073 | 1,338 | — | (2,676) | 735 |
| Deferred charges and other assets | 249,179 | 1,461 | 5,737 | 19,831 | — | 276,208 |
| | $5,253,369 | $603,745 | $627,794 | $105,707 | $(937,088) | $5,653,527 |
| CAPITALIZATION AND LIABILITIES | | | | | | |
| Shareholders' equity | $1,602,422 | $144,827 | $ 53,426 | $ 33,089 | $(231,342) | $1,602,422 |
| Long-term debt | 2,177,279 | — | — | 5,825 | — | 2,183,104 |
| Total capitalization | 3,779,701 | 144,827 | 53,426 | 38,914 | (231,342) | 3,785,526 |
| Current liabilities | | | | | | |
| Current maturities of long-term debt | 1,250 | — | — | 2,014 | — | 3,264 |
| Short-term debt | 144,809 | 60,000 | — | 51,320 | (111,320) | 144,809 |
| Liabilities from risk management activities | — | 63,936 | 25,038 | — | (27,054) | 61,920 |
| Other current liabilities | 623,300 | 217,777 | 95,557 | 4,963 | (38,835) | 902,762 |
| Intercompany payables | — | 87,968 | 437,893 | — | (525,861) | — |
| Total current liabilities | 769,359 | 429,681 | 558,488 | 58,297 | (703,070) | 1,112,755 |
| Deferred income taxes | 268,108 | 12,369 | 9,563 | 2,167 | — | 292,207 |
| Noncurrent liabilities from risk management activities | — | 16,654 | 1,338 | — | (2,676) | 15,316 |
| Regulatory cost of removal obligation | 263,424 | — | — | — | — | 263,424 |
| Deferred credits and other liabilities | 172,777 | 214 | 4,979 | 6,329 | — | 184,299 |
| | $5,253,369 | $603,745 | $627,794 | $105,707 | $(937,088) | $5,653,527 |

## 18. Related Party Transactions

AEM provides a variety of natural gas management services to our Kentucky, Louisiana and Mid-States divisions including furnishing natural gas supplies at fixed and market-based prices and the management of certain of our underground storage facilities. Additionally, at times, AEM places financial instruments for our various divisions to partially insulate us and our customers from gas price volatility.

Atmos Pipeline and Storage, L.L.C. provides asset management services for certain of our utility storage fields in exchange for a contractually negotiated demand charge. The Atmos Pipeline — Texas Division, a division of Atmos, provides natural gas transportation services to our Atmos Energy Mid-Tex Division.

Atmos Energy Services, L.L.C., provides natural gas management services for our own utility operations, other than the Mid-Tex Division. Prior to the second quarter of fiscal 2004, this entity conducted limited operations. However, beginning in April 2004, AES began providing natural gas supply management services to our utility operations in a limited number of states. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices.

The following summarizes our significant affiliate transactions with AEM, APS and AES.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | (In thousands, unless otherwise indicated) | | |
| Gas purchases[1]: | | | |
| Dollars | $471,844 | $227,315 | $235,320 |
| Volumes (Mcf) | 52,554 | 31,370 | 42,518 |
| Average sales price per Mcf | $ 8.98 | $ 7.25 | $ 5.53 |
| Storage contract fees | $ 1,792 | $ 1,753 | $ 2,765 |
| Natural gas management services | $ 3,573 | $ 2,986 | $ 682 |

(1) Gas purchases are made in a competitive bidding process, reflect market prices and exclude demand and other charges.

JD Woodward was Senior Vice President, Nonutility Operations of the Company from April 2001 to April 2006. Woodward Marketing L.L.C., a wholly-owned subsidiary of the Company through September 30, 2003 and its successor, AEM, leased office space from one corporation owned by Mr. Woodward. The lease originated in April 2002 and was terminated in July 2006.

During 2006, 2005 and 2004, our utility division leased office space and vehicles from our natural gas marketing and other nonutility segments. Base lease payments were $1.1 million, $1.0 million and $1.2 million in 2006, 2005 and 2004.

## 19. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

| | Quarter Ended | | | |
|---|---|---|---|---|
| | December 31 | March 31 | June 30 | September 30 |
| | (In thousands, except per share data) | | | |
| **Fiscal year 2006:** | | | | |
| Operating revenues | | | | |
| Utility segment | $1,405,010 | $1,447,620 | $ 402,044 | $ 395,917 |
| Natural gas marketing segment | 1,101,845 | 818,629 | 562,447 | 673,603 |
| Pipeline and storage segment | 39,712 | 45,483 | 35,862 | 39,510 |
| Other nonutility segment | 1,492 | 1,595 | 1,413 | 1,398 |
| Intersegment eliminations | (264,239) | (279,481) | (138,523) | (138,974) |
| | 2,283,820 | 2,033,846 | 863,243 | 971,454 |
| Gross profit | 346,590 | 405,403 | 204,500 | 260,077 |
| Operating income | 149,697 | 180,833 | 4,803 | 47,283 |
| Net income (loss) | 71,027 | 88,796 | (18,145) | 6,059 |
| Net income (loss) per basic share | $ 0.88 | $ 1.10 | $ (0.22) | $ 0.07 |
| Net income (loss) per diluted share | $ 0.88 | $ 1.10 | $ (0.22) | $ 0.07 |
| **Fiscal year 2005:** | | | | |
| Operating revenues | | | | |
| Utility segment | $ 913,681 | $1,235,377 | $ 501,735 | $ 452,347 |
| Natural gas marketing segment | 493,801 | 512,891 | 466,835 | 632,751 |
| Pipeline and storage segment | 43,690 | 45,546 | 33,449 | 30,604 |
| Other nonutility segment | 1,359 | 1,278 | 1,421 | 1,244 |
| Intersegment eliminations | (83,907) | (110,007) | (96,563) | (115,659) |
| | 1,368,624 | 1,685,085 | 906,877 | 1,001,287 |
| Gross profit | 322,103 | 375,894 | 221,274 | 198,366 |
| Operating income | 128,674 | 172,181 | 39,468 | 8,332 |
| Net income (loss) | 59,599 | 88,502 | 4,486 | (16,802) |
| Net income (loss) per basic share | $ 0.79 | $ 1.12 | $ 0.06 | $ (0.21) |
| Net income (loss) per diluted share | $ 0.79 | $ 1.11 | $ 0.06 | $ (0.21) |

**ITEM 9.** ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

**ITEM 9A.** ***Controls and Procedures***

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

We have established disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit to the United States Securities and Exchange Commission under the Securities and Exchange Act of 1934, as amended (the "Act"), is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Under the supervision and with the participation of our management, including our Chairman, President and Chief Executive Officer ("Principal Executive Officer") and our Senior Vice President and Chief Financial Officer ("Principal Financial Officer"), we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Act. Based on this evaluation, our Principal Executive Officer and our Principal Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2006 in ensuring that information required to be disclosed by us in this annual report on Form 10-K was accumulated and communicated to our management, including our Principal Executive and Principal Financial Officers, as appropriate, to allow timely decisions regarding required disclosure.

**Management's Report on Internal Control over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2006.

Ernst & Young LLP has issued its report on management's assessment and on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ ROBERT W. BEST
Robert W. Best
Chairman, President and Chief Executive Officer

/s/ JOHN P. REDDY
John P. Reddy
Senior Vice President and Chief Financial Officer

November 20, 2006

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors
Atmos Energy Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Atmos Energy Corporation maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Atmos Energy Corporation maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atmos Energy Corporation as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2006 of Atmos Energy Corporation and our report dated November 20, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 20, 2006

## Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### ITEM 9B. *Other Information*

Not applicable.

# PART III

### ITEM 10. *Directors and Executive Officers of the Registrant*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007. Information regarding executive officers is included in Part I of this Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance". In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance".

### ITEM 11. *Executive Compensation*

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

### ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Security ownership of certain beneficial owners and of management is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007. Information concerning our equity compensation plans is provided in Part II, Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, of this Annual Report on Form 10-K.

### ITEM 13. *Certain Relationships and Related Transactions*

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

**ITEM 14.** ***Principal Accountant Fees and Services***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

## PART IV

**ITEM 15.** ***Exhibits and Financial Statement Schedules***

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.7(a) through 10.16(e) are management contracts or compensatory plans or arrangements.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY

John P. Reddy
*Senior Vice President*
*and Chief Financial Officer*

Date: November 22, 2006

**POWER OF ATTORNEY**

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Robert W. Best and John P. Reddy, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

| | | |
|---|---|---|
| /s/ ROBERT W. BEST<br>Robert W. Best | Chairman, President and Chief Executive Officer | November 22, 2006 |
| /s/ JOHN P. REDDY<br>John P. Reddy | Senior Vice President and Chief Financial Officer | November 22, 2006 |
| /s/ F. E. MEISENHEIMER<br>F. E. Meisenheimer | Vice President and Controller (Principal Accounting Officer) | November 22, 2006 |
| /s/ TRAVIS W. BAIN, II<br>Travis W. Bain, II | Director | November 22, 2006 |
| /s/ DAN BUSBEE<br>Dan Busbee | Director | November 22, 2006 |
| /s/ RICHARD W. CARDIN<br>Richard W. Cardin | Director | November 22, 2006 |
| /s/ THOMAS J. GARLAND<br>Thomas J. Garland | Director | November 22, 2006 |
| /s/ RICHARD K. GORDON<br>Richard K. Gordon | Director | November 22, 2006 |
| /s/ GENE C. KOONCE<br>Gene C. Koonce | Director | November 22, 2006 |

| | | |
|---|---|---|
| /s/ THOMAS C. MEREDITH<br>Thomas C. Meredith | Director | November 22, 2006 |
| /s/ PHILLIP E. NICHOL<br>Phillip E. Nichol | Director | November 22, 2006 |
| /s/ NANCY K. QUINN<br>Nancy K. Quinn | Director | November 22, 2006 |
| /s/ STEPHEN R. SPRINGER<br>Stephen R. Springer | Director | November 22, 2006 |
| /s/ CHARLES K. VAUGHAN<br>Charles K. Vaughan | Director | November 22, 2006 |
| /s/ RICHARD WARE II<br>Richard Ware II | Director | November 22, 2006 |

**Schedule II**

## ATMOS ENERGY CORPORATION

### Valuation and Qualifying Accounts
### Three Years Ended September 30, 2006

| | Balance at Beginning of Period | Additions: Charged to Cost & Expenses | Additions: Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| | | | (In thousands) | | |
| 2006 | | | | | |
| Allowance for doubtful accounts | $ 15,613 | $ 21,819 | $ — | $ 23,746[2] | $ 13,686 |
| 2005 | | | | | |
| Allowance for doubtful accounts | $ 7,214 | $ 20,293 | $4,563[1] | $ 16,457[2] | $ 15,613 |
| 2004 | | | | | |
| Allowance for doubtful accounts | $ 13,051 | $ 5,379 | $ — | $ 11,216[2] | $ 7,214 |

(1) Represents allowance for doubtful accounts recorded in connection with the TXU Gas acquisition.

(2) Uncollectible accounts written off.

## EXHIBITS INDEX
### Item 14.(a)(3)

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| | *Plan of Reorganization* | |
| 2.1(a) | Agreement and Plan of Merger and Reorganization dated as of September 21, 2001, by and among Atmos Energy Corporation, Mississippi Valley Gas Company and the Shareholders Named on the Signature Pages hereto | Exhibit 2.2 to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042) |
| 2.1(b) | Agreement and Plan of Merger by and between TXU Gas Company and LSG Acquisition Corporation dated June 17, 2004 | Exhibit 2.1 to Form 8-K dated June 17, 2004 (File No. 1-10042) |
| 2.1(c) | Amendment No. 1 to Merger Agreement, dated as of September 30, 2004, by and between LSG Acquisition Corporation and TXU Gas Company LP | Exhibit 2.1 to Form 8-K dated September 30, 2004 (File No. 1-10042) |
| | *Articles of Incorporation and Bylaws* | |
| 3.1 | Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005) | Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042) |
| 3.2 | Amended and Restated Bylaws of Atmos Energy Corporation (as of August 13, 2003) | Exhibit 4.2 to Form S-3 dated August 31, 2004 (File No. 333-118706) |
| | *Instruments Defining Rights of Security Holders* | |
| 4.1 | Specimen Common Stock Certificate (Atmos Energy Corporation) | Exhibit (4)(b) to Form 10-K for fiscal year ended September 30, 1988 (File No. 1-10042) |
| 4.2 | Rights Agreement, dated as of November 12, 1997, between the Company and BankBoston, N.A., as Rights Agent | Exhibit 4.1 to Form 8-K dated November 12, 1997 (File No. 1-10042) |
| 4.3 | First Amendment to Rights Agreement dated as of August 11, 1999, between the Company and BankBoston, N.A., as Rights Agent | Exhibit 2 to Form 8-A, Amendment No. 1, dated August 12, 1999 (File No. 1-10042) |
| 4.4 | Second Amendment to Rights Agreement dated as of February 13, 2002, between the Company and EquiServe Trust Company, N.A., fka BankBoston, N.A., as Rights Agent | Exhibit 4 to Form 10-Q for quarter ended December 31, 2001 (File No. 1-10042) |
| 4.5 | Registration Rights Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company | Exhibit 99.2 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042) |
| 4.6 | Standstill Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company | Exhibit 99.3 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042) |
| 4.7 | Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee | Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706) |
| 4.8 | Indenture between Atmos Energy Corporation, as Issuer, and SunTrust Bank, Trustee dated as of May 22, 2001 | Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042) |

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 4.9(a) | Indenture of Mortgage, dated as of July 15, 1959, from United Cities Gas Company to First Trust of Illinois, National Association, and M.J. Kruger, as Trustees, as amended and supplemented through December 1, 1992 (the Indenture of Mortgage through the 20th Supplemental Indenture) | Exhibit to Registration Statement of United Cities Gas Company on Form S-3 (File No. 33-56983) |
| 4.9(b) | Twenty-First Supplemental Indenture dated as of February 5, 1997 by and among United Cities Gas Company and Bank of America Illinois and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959 | Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042) |
| 4.9(c) | Twenty-Second Supplemental Indenture dated as of July 29, 1997 by and among Atmos Energy Corporation and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959 | Exhibit 4.10(c) to Form S-3 dated August 31, 2004 (File No. 333-118706) |
| 4.10(a) | Indenture between United Cities Gas Company and Bank of America Illinois, as Trustee dated as of November 15, 1995 | Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706) |
| 4.10(b) | First Supplemental Indenture between Atmos Energy Corporation and Bank of America Illinois, as Trustee dated as of July 29, 1997 | Exhibit 4.11(b) to Form S-3 dated August 31, 2004 (File No. 333-118706) |
| 4.11(a) | Debenture Certificate for the 6¾% Debentures due 2028 | Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042) |
| 4.11(b) | Global Security for the 7⅜% Senior Notes due 2011 | Exhibit 99.2 to Form 8-K dated May 15, 2001 (File No. 1-10042) |
| 4.11(c) | Global Security for the 5⅛% Senior Notes due 2013 | Exhibit 10(2)(c) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042) |
| 4.11(d) | Global Security for the Floating Rate Senior Notes due 2007 | Exhibit 10(2)(d) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042) |
| 4.11(e) | Global Security for the 4.00% Senior Notes due 2009 | Exhibit 10(2)(e) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042) |
| 4.11(f) | Global Security for the 4.95% Senior Notes due 2014 | Exhibit 10(2)(f) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042) |
| 4.11(g) | Global Security for the 5.95% Senior Notes due 2034 | Exhibit 10(2)(g) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042) |
| | *Material Contracts* | |
| 10.1 | Guaranty of Atmos Energy Corporation dated June 17, 2004 | Exhibit 10.2 to Form 8-K dated June 17, 2004 (File No. 1-10042) |
| 10.2(a) | Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Gas Company LP | Exhibit 10.1 to Form 8-K dated September 30, 2004 (File No. 1-10042) |
| 10.2(b) | Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation, Oncor Utility Solutions (Texas) Company and TXU Electric Delivery Company | Exhibit 10.2 to Form 8-K dated September 30, 2004 (File No. 1-10042) |

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 10.2(c) | Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Business Services Company (Exhibit A to Schedule 2 containing listing of employee credit and procurement cards is omitted, to be supplementally furnished to the Commission upon request) | Exhibit 10.3 to Form 8-K dated September 30, 2004 (File No. 1-10042) |
| 10.2(d) | Transitional Access Agreement, dated as of October 1, 2004, by and among Atmos Energy Corporation and TXU Energy Retail Company LP, TXU Business Services Company, TXU Properties Company and TXU Electric Delivery Company | Exhibit 10.4 to Form 8-K dated September 30, 2004 (File No. 1-10042) |
| 10.3 | Revolving Credit Agreement (3 Year Facility), dated as of October 18, 2005, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent and Bank of America, N.A., Wachovia Bank, National Association and Societe Generale, as Co-Documentation Agents, and the lenders from time to time parties thereto | Exhibit 10.1 to Form 8-K dated October 18, 2005 (File No. 1-10042) |
| 10.4 | Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership | Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042) |
| 10.5(a) | Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties thereto. | Exhibit 10.1 to Form 8-K dated March 30, 2005 (File No. 1-10042) |
| 10.5(b) | First Amendment, dated as of November 28, 2005, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Société Générale, and the other financial institutions which may become parties thereto. | Exhibit 10.1 to Form 8-K dated November 28, 2005 (File No. 1-10042) |
| 10.5(c) | Second Amendment, dated as of March 31, 2006, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Société Générale and the other financial institutions which may become parties thereto | Exhibit 10.1 to Form 8-K dated March 31, 2006 (File No. 1-10042) |

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 10.6 | Revolving Credit Agreement (364 Day Facility), dated as of November 7, 2006, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent and Bank of America, N.A., JPMorgan Chase Bank, N.A., and the Royal Bank of Scotland, Plc as Co-Documentation Agents, and the lenders from time to time parties thereto | Exhibit 10.1 to Form 8-K dated November 7, 2006 (File No. 1-10042) |
| | *Executive Compensation Plans and Arrangements* | |
| 10.7(a)* | Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I | Exhibit 10.21(b) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042) |
| 10.7(b)* | Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier I | Exhibit 10.1 to Form 8-K dated May 9, 2006 (File No. 1-10042) |
| 10.7(c)* | Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II | Exhibit 10.21(c) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042) |
| 10.7(d)* | Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier II | Exhibit 10.2 to Form 8-K dated May 9, 2006 (File No. 1-10042) |
| 10.8* | Atmos Energy Corporation Long-Term Stock Plan for the United Cities Gas Company Division | Exhibit 99.1 to Form S-8 filed July 29, 1997 (File No. 333-32343) |
| 10.9(a)* | Atmos Energy Corporation Executive Retiree Life Plan | Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042) |
| 10.9(b)* | Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan | Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042) |
| 10.10(a)* | Description of Financial and Estate Planning Program | Exhibit 10.25(b) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042) |
| 10.10(b)* | Description of Sporting Events Program | Exhibit 10.26(c) to Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042) |
| 10.11(a)* | Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 12, 1998 | Exhibit 10.26 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042) |
| 10.11(b)* | Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date August 12, 1998 | Exhibit 10.32 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042) |
| 10.11(c)* | Amendment No. One to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date January 1, 1999 | Exhibit 10.2 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042) |
| 10.11(d)* | Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000 | Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042) |
| 10.11(e)* | Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan | Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042) |
| 10.12* | Atmos Energy Corporation Executive Nonqualified Deferred Compensation Plan | Exhibit 10.33 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042) |

| Exhibit Number | Description | Page Number or Incorporation by Reference to |
|---|---|---|
| 10.13(a)* | Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994 | Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042) |
| 10.13(b)* | Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001 | Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042) |
| 10.13(c)* | Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002 | Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042) |
| 10.14* | Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors | Exhibit C to Definitive Proxy Statement on Schedule 14A filed December 30, 1998 (File No. 1-10042) |
| 10.15* | Atmos Energy Corporation Outside Directors Stock-for-Fee Plan (Amended and Restated as of November 12, 1997) | Exhibit 10.28 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042) |
| 10.16(a)* | Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 14, 2002) | Exhibit 10.1 to Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042) |
| 10.16(b)* | Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan | Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042) |
| 10.16(c)* | Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan | Exhibit 10.16(c) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042) |
| 10.16(d)* | Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan | Exhibit 10.16(d) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042) |
| 10.16(e)* | Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 14, 2002) | Exhibit 10.2 to Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042) |
| 12 | Statement of computation of ratio of earnings to fixed charges | |
| | *Other Exhibits, as indicated* | |
| 21 | Subsidiaries of the registrant | |
| 23 | Consent of independent registered public accounting firm, Ernst & Young LLP | |
| 24 | Power of Attorney | Signature page of Form 10-K for fiscal year ended September 30, 2006 |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications | |
| 32 | Section 1350 Certifications ** | |
| 99 | Annual Certification Pursuant to Section 303A.12 of the New York Stock Exchange Listed Company Manual | |

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange 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.