# **Piedmont Natural Gas** 2009 Summary Annual Report



share the *warmth*

# Piedmont Natural Gas board of directors

**Jerry W. Amos**
*Retired Attorney at Law*
*Seabrook Island, South Carolina*

**E. James Burton**
*Dean of the Jennings A. Jones*
*College of Business*
*Middle Tennessee State University*
*Murfreesboro, Tennessee*

**Malcolm E. Everett III**
*Lead Independent Director*
*Retired Senior Executive Vice President*
*Wachovia Corporation*
*Charlotte, North Carolina*

**John W. Harris**
*President*
*Lincoln Harris LLC*
*Charlotte, North Carolina*

**Aubrey B. Harwell, Jr.**
*Managing Partner*
*Neal & Harwell, PLC*
*Nashville, Tennessee*

**Frank B. Holding, Jr.**
*Chairman and Chief Executive Officer*
*First Citizens BancShares, Inc.*
*Raleigh, North Carolina*

**Frankie T. Jones, Sr.**
*President and Chief Executive Officer*
*Phoenix One Enterprises, Inc.*
*High Point, North Carolina*

**Vicki McElreath**
*Retired Audit Partner*
*PricewaterhouseCoopers LLP*
*Savannah, Georgia*

**Minor M. Shaw**
*President*
*Micco Corporation*
*Greenville, South Carolina*

**Muriel W. Sheubrooks**
*Retired Partner*
*Greater Carolinas Real Estate Services, Inc.*
*Charlotte, North Carolina*

**David E. Shi**
*President*
*Furman University*
*Greenville, South Carolina*

**Thomas E. Skains**
*Chairman, President and*
*Chief Executive Officer*
*Piedmont Natural Gas Company, Inc.*
*Charlotte, North Carolina*

# executive officers

**David J. Dzuricky**
*Senior Vice President and*
*Chief Financial Officer*

**A. Leslie Ennis**
*Vice President*
*Information Services*

**Jane R. Lewis-Raymond**
*Vice President, General Counsel,*
*Chief Ethics and Compliance Officer*
*and Corporate Secretary*

**June B. Moore**
*Vice President*
*Enterprise Quality Management*

**Kevin M. O'Hara**
*Senior Vice President*
*Corporate and Community Affairs*

**Robert O. Pritchard**
*Vice President*
*Treasurer and Chief Risk Officer*

**Jose M. Simon**
*Vice President*
*Controller*

**Thomas E. Skains**
*Chairman, President and*
*Chief Executive Officer*

**Kenneth T. Valentine**
*Vice President*
*Business Development and Carbon*
*Management Strategies*

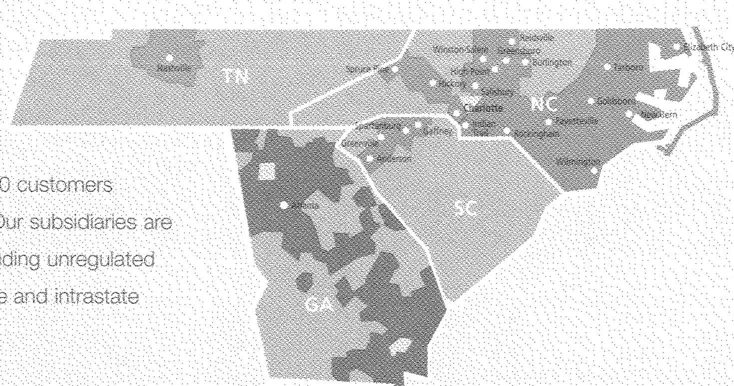
**Ranelle Q. Warfield**
*Vice President*
*Customer Service*

**William C. (Bill) Williams**
*Vice President*
*Sales and Delivery Services*

**Franklin H. Yoho**
*Senior Vice President*
*Commercial Operations*

**Michael H. Yount**
*Senior Vice President*
*Utility Operations*

About the Company Piedmont Natural Gas is an energy services company primarily engaged in the distribution of natural gas to more than one million residential, commercial and industrial utility customers in North Carolina, South Carolina and Tennessee, including 61,000 customers served by municipalities who are wholesale customers. Our subsidiaries are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.




Piedmont Natural Gas

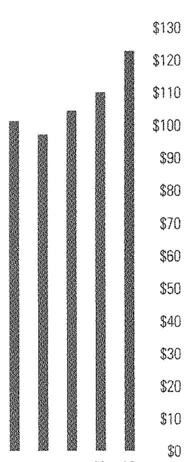
SouthStar Energy Services, our unregulated retail natural gas marketing joint venture, d.b.a. Georgia Natural Gas

# financial highlights

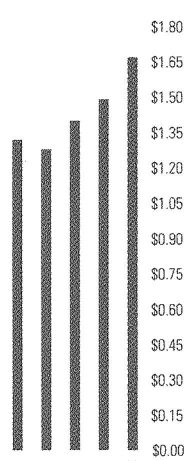
| *In thousands except per share amounts, degree days and customer additions* | **2009** | 2008 | Percent Change |
|---|---|---|---|
| **Earnings and Dividends** | | | |
| Net Income | **$ 122,824** | $ 110,007 | 11.7 % |
| Earnings Per Share of Common Stock: | | | |
| Basic | **$ 1.68** | $ 1.50 | 12.0 % |
| Diluted | **$ 1.67** | $ 1.49 | 12.1 % |
| Dividends Per Share | **$ 1.07** | $ 1.03 | 3.9 % |
| **Margin, Revenues and Volumes** | | | |
| Margin (Operating Revenues less Cost of Gas) | **$ 561,574** | $ 552,973 | 1.6 % |
| Operating Revenues | **$ 1,638,116** | $ 2,089,108 | (21.6)% |
| Gas Volumes – Dekatherms: | | | |
| Sales | **110,379** | 110,801 | (0.4)% |
| Transportation | **106,495** | 99,450 | 7.1 % |
| Total System Throughput | **216,874** | 210,251 | 3.2 % |
| Secondary Market Sales | **46,057** | 53,442 | (13.8)% |
| Degree Days – System Average | **3,413** | 3,195 | 6.8 % |
| **Construction and Customer Additions** | | | |
| Utility Construction Expenditures | **$ 129,006** | $ 181,001 | (28.7)% |
| Gross Customer Additions | **12,600** | 20,500 | (38.5)% |
| Net Utility Plant – Year End | **$2,304,392** | $ 2,240,834 | 2.8 % |
| **Common Stock** | | | |
| Book Value Per Share – Year End | **$ 12.67** | $ 12.11 | 4.6 % |
| Market Value Per Share – Year End | **$ 23.28** | $ 32.92 | (29.3)% |
| Average Shares of Common Stock: | | | |
| Basic | **73,171** | 73,334 | (0.2)% |
| Diluted | **73,461** | 73,612 | (0.2)% |

*This report contains forward-looking statements. These statements are based on management's current expectations and information currently available and are believed to be reasonable and are made in good faith. However, the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those projected in the statements. Factors that may make the actual results differ from anticipated results include, but are not limited to, regulatory issues, customer growth, economic and capital market conditions, the cost and availability of natural gas, competition from other energy providers, weather conditions and other uncertainties, all of which are difficult to predict and some of which are beyond our control. For these reasons, you should not rely on these forward-looking statements when making investment decisions. The words "expect," "believe," "project," "anticipate," "intend," "should," "could," "will," "assume," "can," "estimate," "forecast," "future," "indicate," "outlook," "plan," "predict," "seek," "target," "would," and variations of such words and similar expressions are intended to identify forward-looking statements. Forward-looking statements are only as of the date they are made and we do not undertake any obligation to update publicly any forward-looking statement, either as a result of new information, future events or otherwise except as required by applicable laws and regulations. More information about the risks and uncertainties relating to these forward-looking statements may be found in Piedmont's latest Form 10-K and its other filings with the SEC, which are available on the SEC's website at http://www.sec.gov.*

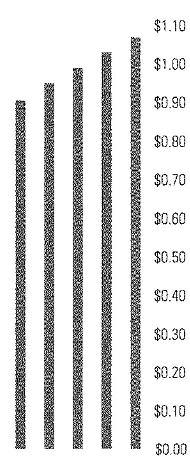
**Net Income** *in millions*




**Earnings Per Share** *Diluted*




**Dividends Per Share**



# dear shareholders

Throughout fiscal year 2009, we faced significant economic challenges marked by crises in the financial and housing markets, falling consumer confidence and a global recession. It was a turbulent year with much uncertainty, but one where sound companies were able to emerge with financial strength by focusing on their business mission, sticking to their strategic and operating fundamentals, and living their core values. We are pleased to report that through it all, your company delivered another year of solid financial performance, dividend growth and record earnings to its shareholders. As we enter 2010, we are positioned to take advantage of future growth opportunities in an ever changing energy landscape. Before I recap 2009 and discuss our opportunities ahead, however, I want to thank each and every one of my 1,814 Piedmont Natural Gas teammates for their valuable contribution to our success in 2009 and gratefully acknowledge their commitment to shareholder value, service excellence, and safe and reliable natural gas operations.

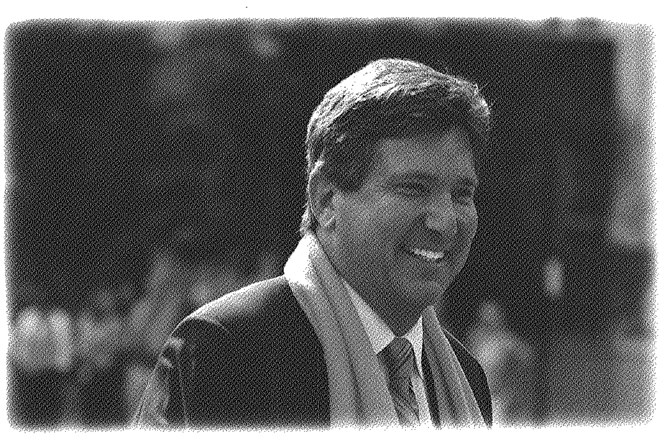
Our 2009 Achievements In fiscal year 2009, we achieved record net income and earnings per diluted share of $122.8 million and $1.67, respectively, both up 12 percent from 2008. These results were achieved by top line margin growth from continued new customer additions, expense reductions from ongoing cost management and process improvement programs – our third consecutive year of lower O&M costs - and an improvement in joint venture earnings.

Piedmont's cumulative total shareholder return (stock price appreciation and dividends) for the five-year period ending October 31, 2009 was 24 percent. This compares to a cumulative total shareholder return of 2 percent for the S&P 500. In March, your Board of Directors increased the dividend for the 31st consecutive year. The new $1.08 annualized dividend was a 3.8 percent increase over the prior year.

During 2009, growth in our residential and commercial new construction markets declined as a result of the economic recession. Even so, we added 12,600 new customers to our distribution system, a gross customer addition growth rate of 1.3 percent, and we remain one of the fastest-growing natural gas utilities in the nation. We made great strides in our conversion markets – up 62 percent from 2008 – reflecting the comfort, reliability and overall value that energy consumers attach to natural gas.

In July, we reached an agreement with AGL Resources to restructure our SouthStar Energy joint venture by selling one-half of our 30 percent ownership interest to AGLR effective January 1, 2010 for $57.5 million. The new agreement creates long term certainty for our remaining 15 percent ownership stake, better aligns our

Tom Skains,
Chairman,
President and
Chief Executive
Officer



strategic interests in SouthStar and reaffirms the focus of our core business on natural gas utility operations in our growing Southeast markets.

In October, we announced an agreement with Progress Energy Carolinas to provide natural gas delivery service to its new state-of-the-art power generation facility to be built in Wayne County, North Carolina. Under the agreement, we will invest an estimated $85 million to construct 38-miles of new transmission pipeline and associated compression facilities in time for an expected July, 2012 in service date.

Also in October, we announced a realignment of our executive management team to further strengthen our continuing focus on customer-oriented improvements in our business processes and better position us to take advantage of the future opportunities for natural gas and related services in a new energy economy.

The Role of Natural Gas in a New Low-Carbon Energy Economy We believe that natural gas is uniquely positioned to provide broad-based solutions to our nation's energy and environmental challenges. Natural gas is a much cleaner energy source than coal or oil, its transmission from energy source to site of consumption is three times more efficient than electricity, and 98 percent of the natural gas used in our country comes from North American sources. In addition, recent industry studies confirm that we have nearly a 100 year supply of natural gas under American soil – free from foreign influence and intervention. The expanded use of natural gas in homes, businesses and industries, and in power generation and transportation markets across our country can help revitalize our economy, reduce overall greenhouse gas emissions and enhance our national energy security. For this reason, we believe that natural gas is not just a "bridge" fuel to a new, secure, low-carbon energy economy - we believe it is a destination fuel.

Our Service and Our Values At Piedmont, we work hard to deliver the many benefits of natural gas to our customers – including comfort, convenience and quality of life - through reliable service supported by our core values. Along with our regulators and valued shareholders, our customers count on us to perform that service safely and efficiently. We must continually earn our place in a customer's home or business, knowing that natural gas is a customer's choice for energy and not a necessity.

To that end, we pursue a culture of accountability at Piedmont that emphasizes integrity, respect, excellence, health and stewardship. We acknowledge and appreciate the trust that has been placed in us and we look forward to serving the energy needs of our current and future customers and our local communities for many years to come.

On behalf of your Piedmont Natural Gas Board, management and employee team, we look forward to the challenges and opportunities ahead and thank you for your continued confidence and support.

**Thomas E. Skains**
Chairman, President and Chief Executive Officer
January 14, 2010

Piedmont Natural Gas

# *share the warmth* round up

"Small Change to Change Lives" In July 2009, Piedmont introduced its new *Share the Warmth* Round Up program to customers in North Carolina, South Carolina, and Tennessee. Recognizing the significant economic challenges that many families face and the difficult financial choices they must make each month, Piedmont's new program seeks to provide some measure of emergency energy assistance to those in our communities who need it the most. The voluntary program, which rounds a customer's monthly bill up to the nearest dollar, donates 100 percent of the proceeds to help an individual or family pay their home energy bill. Funds are provided regardless of what source of energy is used in the home and no matter what time of year the need for assistance arises.

Piedmont is one of only a few natural gas utilities across the country that has implemented a "round up" program and is the largest utility in the Southeast to offer one to its customers. By the end of 2009, nearly 6,500 Piedmont customers in North Carolina, South Carolina and Tennessee were participating in the program. Over the course of the next year, Piedmont hopes that many thousands more of our customers will have enrolled in *Share the Warmth* Round Up to help our neighbors in need.

Making a Difference At Piedmont, we understand the importance of being an integral part of the communities we serve. Employee volunteerism, civic leadership and participation, and of course financial contributions all represent important aspects of our philosophy around community involvement and partnership. So, In addition to helping spread the word about *Share the Warmth* Round Up through monthly bill inserts and special media events within our communities, the Piedmont Natural Gas Foundation contributes annually to the *Share the Warmth* Round Up program. In July, at a series of events held on the same day across our three-state service area and in partnership with local charitable agencies and officials, Piedmont committed to a $100,000 contribution to *Share the Warmth* Round Up and pledged an additional $50,000 contribution in October. Each event drew wide-spread media attention, with local officials and hundreds of Piedmont employees on hand to show their support and wear the trademark orange scarves that have become a recognizable symbol of the *Share the Warmth* program.

If you would like to learn more about our *Share the Warmth* Round Up program or to enroll in the program, please visit our website at www.piedmontng.com and click on the *Share the Warmth* link. It truly is "Small Change to Change Lives."

**A simple way to help neighbors in need pay their home energy bills**

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 October 31, 2009**

**or**

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

For the transition period from ____________ to ______________

Commission file number 1-6196

SEC Mail Processing Section
Washington, DC
109

**Piedmont Natural Gas Company, Inc.**
(Exact name of registrant as specified in its charter)

| North Carolina | 56-0556998 |
|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

| 4720 Piedmont Row Drive, Charlotte, North Carolina | 28210 |
|---|---|
| (Address of principal executive offices) | (Zip Code) |

Registrant's telephone number, including area code (704) 364-3120

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 |

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer ☒ | Accelerated filer ☐ |
| Non-accelerated filer ☐ (Do not check if a smaller reporting company) | Smaller reporting company ☐ |

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

State the aggregate market value of the voting common equity held by non-affiliates of the registrant as of April 30, 2009.

Common Stock, no par value - $ 1,762,419,954

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

| Class | Outstanding at December 11, 2009 |
|---|---|
| Common Stock, no par value | 73,295,803 |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the Proxy Statement for the Annual Meeting of Shareholders on February 26, 2010, are incorporated by reference into Part III.

Piedmont Natural Gas Company, Inc.

2009 FORM 10-K ANNUAL REPORT

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## PART I

### Item 1. Business

Piedmont Natural Gas Company, Inc. (Piedmont) was incorporated in New York in 1950 and began operations in 1951. In 1994, we merged into a newly formed North Carolina corporation with the same name for the purpose of changing our state of incorporation to North Carolina.

Piedmont is an energy services company whose principal business is the distribution of natural gas to over one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 61,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We provide service to Anderson, Gaffney, Greenville and Spartanburg in South Carolina and Charlotte, Salisbury, Greensboro, Winston-Salem, High Point, Burlington, Hickory, Indian Trail, Spruce Pine, Reidsville, Fayetteville, New Bern, Wilmington, Tarboro, Elizabeth City, Rockingham and Goldsboro in North Carolina. In North Carolina, we also provide wholesale natural gas service to Greenville, Monroe, Rocky Mount and Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to Gallatin and Smyrna.

We have two reportable business segments, regulated utility and non-utility activities. The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. Factors critical to the success of the regulated segment include a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in the rates charged to customers. For the year ended October 31, 2009, 84% of our earnings before taxes came from our regulated utility segment. The non-utility activities segment consists of our equity method investments in joint venture, energy-related businesses that are involved in unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. For the year ended October 31, 2009, the earnings before taxes from our non-utility segment was 16%, which consisted of 4% from regulated non-utility activities and 12% from unregulated non-utility activities. Operations of both segments are conducted within the United States of America. For further information on equity method investments and business segments, see Note 11 and Note 12, respectively, to the consolidated financial statements.

Operating revenues shown in the consolidated statements of income represent revenues from the regulated utility segment. The cost of purchased gas is a component of operating revenues. Increases or decreases in prudently incurred purchased gas costs from suppliers are passed on to customers through purchased gas adjustment procedures. Therefore, our operating revenues are impacted by changes in gas costs as well as by changes in volumes of gas sold and transported. For the year ended October 31, 2009, 48% of our operating revenues were from residential customers, 28% from commercial customers, 10% from large volume customers, including industrial, power generation and resale customers, and 14% from secondary market activities. Secondary market transactions consist of off-system sales and capacity release arrangements and are part of our utility gas supply management program with regulator-approved sharing mechanisms between our utility customers and our shareholders. Operations of the non-utility activities segment are included in the consolidated statements of income in "Income from equity method investments" and "Non-operating income."

Our utility operations are regulated by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are also regulated by the NCUC as to the issuance of securities. We are also subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the Federal Energy Regulatory Commission (FERC) that affect the purchase and sale and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. In addition, we are subject to numerous regulations, such as those relating to employment practices, which are generally applicable to companies doing business in the United States of America.

We hold non-exclusive franchises for natural gas service in many of the communities we serve, with expiration dates from 2011 to 2058. The franchises are adequate for the operation of our gas distribution business and do not contain materially burdensome restrictions or conditions. Twenty franchise agreements have expired as of October 31, 2009. We continue to operate in those areas pursuant to the provisions of the expired franchises with no significant impact on our business. No franchise agreements will expire during the 2010 fiscal year. The likelihood of cessation of service under an expired franchise is remote. We believe that these franchises will be renewed or service continued in the ordinary course of business without the necessity of franchises with no material adverse impact on us, as most government entities do not want to prevent their citizens from having access to gas service or to interfere with our required system maintenance.

The natural gas distribution business is seasonal in nature as variations in weather conditions generally result in greater revenues and earnings during the winter months when temperatures are colder. For further information on weather sensitivity and the impact of seasonality on working capital, see "Financial Condition and Liquidity" in Item 7 of this Form 10-K. As is prevalent in the industry, we inject natural gas into storage during the summer months (principally April through October) when customer demand is lower for withdrawal from storage during the winter months (principally November through March) when customer demand is higher. During the year ended October 31, 2009, the amount of natural gas in storage varied from 12.3 million dekatherms (one dekatherm equals 1,000,000 BTUs) to 28.4 million dekatherms, and the aggregate commodity cost of this gas in storage varied from $92.7 million to $265.4 million.

During the year ended October 31, 2009, 123.1 million dekatherms of gas were sold to or transported for large volume customers compared with 121.6 million dekatherms in 2008. Deliveries to temperature-sensitive residential and commercial customers, whose consumption varies with the weather, totaled 93.8 million dekatherms in 2009, compared with 88.7 million dekatherms in 2008. Weather, as measured by degree days, was 3% colder than normal in 2009 and 5% warmer than normal in 2008.

The following is a five-year comparison of operating statistics for the years ended October 31, 2005 through 2009.

| | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| Operating Revenues (in thousands): | | | | | |
| Sales and Transportation: | | | | | |
| Residential | $ 787,994 | $ 813,032 | $ 743,637 | $ 841,051 | $ 686,304 |
| Commercial | 462,160 | 503,317 | 418,426 | 498,956 | 421,499 |
| Industrial | 126,855 | 209,341 | 190,204 | 205,384 | 215,505 |
| For Power Generation | 19,609 | 25,266 | 29,135 | 22,963 | 16,248 |
| For Resale | 11,746 | 12,326 | 13,907 | 11,342 | 40,122 |
| Total | 1,408,364 | 1,563,282 | 1,395,309 | 1,579,696 | 1,379,678 |
| Secondary Market Sales | 221,300 | 515,968 | 308,904 | 337,278 | 373,353 |
| Miscellaneous | 8,452 | 9,858 | 7,079 | 7,654 | 8,060 |
| Total | $ 1,638,116 | $ 2,089,108 | $ 1,711,292 | $ 1,924,628 | $ 1,761,091 |
| Gas Volumes - Dekatherms (in thousands): | | | | | |
| System Throughput: | | | | | |
| Residential | 55,298 | 51,909 | 50,072 | 49,119 | 52,966 |
| Commercial | 38,526 | 36,766 | 33,647 | 34,476 | 36,000 |
| Industrial | 74,363 | 81,780 | 79,266 | 80,490 | 81,102 |
| For Power Generation | 39,639 | 30,875 | 34,096 | 26,099 | 25,591 |
| For Resale | 9,048 | 8,921 | 8,923 | 8,472 | 8,779 |
| Total | 216,874 | 210,251 | 206,004 | 198,656 | 204,438 |
| Secondary Market Sales | 46,057 | 53,442 | 42,049 | 40,994 | 47,057 |
| Number of Retail Customers Billed (12-month average): | | | | | |
| Residential | 855,670 | 852,586 | 835,636 | 815,579 | 792,061 |
| Commercial | 94,404 | 94,045 | 93,472 | 92,692 | 91,645 |
| Industrial | 2,358 | 2,937 | 2,959 | 3,008 | 3,146 |
| For Power Generation | 20 | 20 | 15 | 12 | 16 |
| For Resale | 17 | 17 | 15 | 19 | 15 |
| Total | 952,469 | 949,605 | 932,097 | 911,310 | 886,883 |
| Average Per Residential Customer: | | | | | |
| Gas Used - Dekatherms | 64.63 | 60.88 | 59.92 | 60.23 | 66.87 |
| Revenue | $ 920.91 | $ 953.61 | $ 889.90 | $ 1,031.23 | $ 866.48 |
| Revenue Per Dekatherm | $ 14.25 | $ 15.66 | $ 14.85 | $ 17.12 | $ 12.96 |
| Cost of Gas (in thousands): | | | | | |
| Natural Gas Commodity Costs | $ 727,744 | $ 1,454,073 | $ 1,055,600 | $ 1,229,326 | $ 1,226,999 |
| Capacity Demand Charges | 128,081 | 127,640 | 116,977 | 99,333 | 117,287 |
| Natural Gas Withdrawn From (Injected Into) Storage, net | 126,480 | (78,283) | (12,815) | 15,709 | (35,151) |
| Regulatory Charges (Credits), net | 94,237 | 32,705 | 27,365 | 56,781 | (47,183) |
| Total | $ 1,076,542 | $ 1,536,135 | $ 1,187,127 | $ 1,401,149 | $ 1,261,952 |

| | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| Supply Available for Distribution (dekatherms in thousands): | | | | | |
| Natural Gas Purchased | 149,696 | 159,857 | 143,598 | 140,999 | 155,614 |
| Transportation Gas | 115,519 | 108,332 | 108,355 | 101,414 | 97,959 |
| Natural Gas Withdrawn From (Injected Into) Storage, net | 1,010 | (2,980) | (1,640) | (197) | 856 |
| Company Use | (283) | (135) | (141) | (127) | (133) |
| Total | 265,942 | 265,074 | 250,172 | 242,089 | 254,296 |

We purchase natural gas under firm contracts to meet our design-day requirements for firm sales customers. These contracts provide that we pay a reservation fee to the supplier to reserve or guarantee the availability of gas supplies for delivery. Under these provisions, absent force majeure conditions, any disruption of supply deliverability is subject to penalty and damage assessment against the supplier. We ensure the delivery of the gas supplies to our distribution system to meet the peak day, seasonal and annual needs of our firm customers by using a variety of firm transportation and storage capacity contracts. The pipeline capacity contracts require the payment of fixed demand charges to reserve firm transportation or storage entitlements. We align the contractual agreements for supply with the firm capacity agreements in terms of volumes, receipt and delivery locations and demand fluctuations. We may supplement these firm contracts with other supply arrangements to serve our interruptible market.

As of October 31, 2009, we had contracts for the following pipeline firm transportation capacity in dekatherms per day.

| | |
|---|---|
| Williams-Transco | 632,200 |
| El Paso-Tennessee Pipeline | 74,100 |
| Spectra-Texas Eastern (through East Tennessee and Transco) | 38,000 |
| NiSource-Columbia Gas (through Transco and Columbia Gulf) | 42,800 |
| NiSource-Columbia Gulf | 10,000 |
| ONEOK-Midwestern (through Tennessee, Columbia Gulf, East Tennessee and Transco) | 120,000 |
| Total | 917,100 |

As of October 31, 2009, we had the following assets or contracts for local peaking facilities and storage for seasonal or peaking capacity in dekatherms of daily deliverability to meet the firm demands of our markets with deliverability from 5 days to one year.

| | |
|---|---|
| Piedmont Liquefied Natural Gas (LNG) | 278,000 |
| Pine Needle LNG (through Transco) | 263,400 |
| Williams-Transco Storage | 86,100 |
| NiSource-Columbia Gas Storage | 96,400 |
| Hardy Storage (through Columbia Gas and Transco) | 68,800 |
| Dominion Storage (through Transco) | 13,200 |
| El Paso-Tennessee Pipeline Storage | 55,900 |
| Total | 861,800 |

As of October 31, 2009, we own or have under contract 36.2 million dekatherms of storage capacity, either in the form of underground storage or LNG. This capability is used to supplement or replace regular pipeline supplies.

The source of the gas we distribute is primarily from the Gulf Coast production region and is purchased primarily from major and independent producers and marketers. Natural gas demand is continuing to grow in our service area. As part of our long-term plan to diversify our reliance away from the Gulf Coast region, we receive firm, long-term market area storage service from Hardy Storage Company, LLC (Hardy Storage), a storage facility in West Virginia, and firm, long-term transportation service from Midwestern Gas Transmission Company that provides access to gas supplies from Canadian and Rocky Mountain supply basins via the Chicago hub.

We have deferred the development and construction of our previously announced LNG peak storage facility in Robeson County, North Carolina based on our current growth projections, which indicate that we may need to resume development of the project in 2011 to prepare for construction in 2012 in order provide service in 2015. With the uncertain economic outlook, we will monitor customer growth trends in our markets and plan for the development of the project when needed to meet future customer requirements. For further information on gas supply and regulation, see "Gas Supply and Regulatory Proceedings" in Item 7 of this Form 10-K and Note 2 to the consolidated financial statements.

During the year ended October 31, 2009, approximately 5% of our margin (operating revenues less cost of gas) was generated from deliveries to industrial or large commercial customers that have the capability to burn a fuel other than natural gas. The alternative fuels are primarily fuel oil and propane and, to a much lesser extent, coal or wood. Our ability to maintain or increase deliveries of gas to these customers depends on a number of factors, including weather conditions, governmental regulations, the price of gas from suppliers, availability, and the price of alternate fuels. Under FERC policies, certain large volume customers located in proximity to the interstate pipelines delivering gas to us could bypass us and take delivery of gas directly from the pipeline or from a third party connecting with the pipeline. During the fiscal year ended October 31, 2009, no bypass occurred. During 2009, the City of Monroe, a wholesale customer, began construction of a pipeline to bypass our system with a direct connection to Transco. This action will have no impact on our utility margin as a result of a regulatory provision approved in our last North Carolina rate case. The future level of bypass activity cannot be predicted.

The regulated utility also competes with other energy products, such as electricity and propane, in the residential and small commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. There are four major electric companies within our service areas. We continue to attract the majority of the new residential construction market on or near our distribution mains, and we believe that the consumer's preference for natural gas is influenced by such factors as price, value, availability, environmental attributes, comfort, convenience, reliability, and energy efficiency. Natural gas has historically maintained a price advantage over electricity in our service areas. Increases in the price of natural gas can negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. However, the direct use of natural gas in homes and businesses is the most efficient and cost effective use of natural gas and lowers the carbon footprint of those premises in our market area.

As noted above, many of our industrial customers are capable of burning a fuel other than natural gas, with fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on price with natural gas historically having a price advantage over fuel oil. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the US dollar versus other currencies. Our revenues could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

During the year ended October 31, 2009, our largest customer contributed $52.6 million, or 3.2%, of total operating revenues and less than 1% of total margin.

Our costs for research and development are not material and are primarily limited to natural gas industry-sponsored research projects.

Compliance with federal, state and local environmental protection laws have had no material effect on our construction expenditures, earnings or competitive position. For further information on environmental issues, see "Environmental Matters" in Item 7 of this Form 10-K.

As of October 31, 2009, our fiscal year end, we had 1,821 employees, compared with 1,833 as of October 31, 2008.

Our reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to these reports, are available at no cost on our website at www.piedmontng.com as soon as reasonably practicable after the report is filed with or furnished to the Securities and Exchange Commission (SEC).

## Item 1A. Risk Factors

*Increases in the wholesale price of natural gas could reduce our earnings and working capital.*

The supply and demand balance in natural gas markets could cause an increase in the price of natural gas. The prudently incurred cost we pay for natural gas is passed directly through to our customers. Therefore, significant increases in the price of natural gas may cause our existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders and new customers to select alternative sources of energy. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in new customers could impede growth in our future earnings. In addition, during periods when natural gas prices are higher than historical levels, our working capital costs could increase due to higher carrying costs of gas storage inventories, and customers may have trouble paying higher bills leading to bad debt expenses, which may reduce our earnings.

*A decrease in the availability of adequate upstream, interstate pipeline transportation capacity and natural gas supply could reduce our earnings.*

We purchase all of our gas supply from interstate sources that must then be transported to our service territory. Interstate pipeline companies transport the gas to our system under firm service agreements that are designed to meet the requirements of our core markets. A significant disruption to that supply or interstate pipeline capacity due to unforeseen events, including but not limited to, operational failures or disruptions, hurricanes, freeze off of natural gas wells, terrorist attacks or other acts of war, could reduce our normal interstate supply of gas, which could reduce our earnings. Moreover, if additional natural gas infrastructure, including but not limited to exploration and drilling platforms, processing and gathering systems, off-shore pipelines, interstate pipelines and storage, cannot be built at a pace that meets demand, then our growth opportunities would be limited and our earnings negatively impacted.

*Our business is subject to competition that could negatively affect our results of operations.*

The natural gas business is competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane dealers, renewable energy providers and, as it relates to sources of energy for electric power plants, coal. The primary competitive factor is price.

In residential and commercial customer markets, our natural gas distribution operations compete with other energy products, primarily electricity, fuel oil and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas or decreases in the price of other energy sources could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. In the case of industrial customers, such as manufacturing plants, adverse economic or market conditions, including higher gas costs, could cause these customers to use alternative sources of energy or bypass our systems in favor of special competitive contracts with lower per-unit costs.

Higher gas costs or decreases in the price of other energy sources may allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability and safety and other non-price factors. Technological improvements in other energy sources and events that impair the public perception of these non-price attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers, and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business and adversely affecting our earnings.

*Changes in federal laws or regulations could reduce the availability or increase the cost of our interstate pipeline capacity and/or gas supply and thereby reduce our earnings.*

The FERC has regulatory authority over some of our operations, including sales of natural gas in the wholesale market and the purchase and sale of interstate pipeline and storage capacity. Any Congressional legislation or agency regulation that would alter these or other similar statutory and regulatory structures in a way to significantly raise costs that could not be recovered in rates from our customers, would reduce the availability of supply or capacity, or would reduce our competitiveness, and that could negatively impact our earnings.

*Climate change legislation or regulations could increase our operating costs, negatively affecting our growth, cash flows and earnings.*

There are proposed federal legislative initiatives that attempt to control or limit the causes of climate change, including greenhouse gas emissions such as carbon dioxide. Regulatory agencies may also issue similar climate change regulations. These initiatives could result in various new laws or regulations. Such laws or regulations could impose operational requirements, impose additional charges to fund energy efficiency activities, provide a cost advantage to alternative energy sources other than natural gas, impose costs or restrictions on end users of natural gas, or result in other costs or requirements. As a result, there is a possibility that, when and if enacted, the final form of such legislation or regulation could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and impact the competitive position of natural gas, negatively affecting our growth opportunities, cash flows and earnings.

*Regulatory actions at the state level could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our operating costs as well as reduce our earnings.*

Our regulated utility segment is regulated by the NCUC, the PSCSC and the TRA. These agencies set the rates that we charge our customers for our services. We monitor allowed rates of return and our ability to earn appropriate rates of return based on factors, such as increased operating costs, and initiate general rate proceedings as needed. If a state regulatory commission were to prohibit us from setting rates that timely recover our costs and a reasonable return by significantly lowering our allowed return or negatively altering our cost allocation, rate design, cost trackers (including margin decoupling and cost of gas) or other tariff provisions, then our earnings could be negatively impacted. In the normal course of business in the regulatory environment, assets are placed in service before rate cases can be filed that could result in an adjustment of our returns. 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 may suffer the negative financial effects of having placed in service assets that do not initially earn our authorized rate of return without the benefit of rate relief, which is commonly referred to as "regulatory lag." Rate cases also involve a risk of rate reduction, because once rates have been approved, they are still subject to challenge for their reasonableness by various appropriate entities. Regulatory authorities may also review whether our gas cost purchases are prudent and can adjust the amount of our gas costs that we pass through to our customers. Additionally, our state regulators foster a competitive regulatory model that, for example, allows us to recover any margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may directly access natural gas supply through their own connection to an interstate pipeline. If there were changes in regulatory philosophies that altered our ability to compete for these customers, then we could lose customers or incur significant unrecoverable expenses to retain them. Both scenarios would impact our results of operations, financial condition and cash flows. Our debt and equity financings are also subject to regulation by the NCUC. Delays or failure to receive NCUC approval could limit our ability to access or take advantage of changes in the capital markets. This could negatively impact our liquidity or earnings.

*Weather conditions may cause our earnings to vary from year to year.*

Our earnings can vary from year to year, depending in part on weather conditions.

Currently, we have in place regulatory mechanisms that normalize our margin for weather during the winter, providing for an adjustment up or down, to take into account warmer-than-normal or colder-than-normal weather. We estimate that 80% to 85% of our annual utility margin is collected from temperature-sensitive customers. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell and deliver in any year and the margin we collect from these customers. If our rates and tariffs were modified to eliminate weather protection, such as weather normalization and rate decoupling tariffs, then we would be exposed to significant risk associated with weather and our earnings could vary as a result.

*Our gas supply risk management programs are subject to state regulatory approval or annual review in gas cost proceedings.*

We manage our gas supply costs through short-term and long-term procurement and storage contracts. In the normal course of business, we utilize New York Mercantile Exchange (NYMEX) exchange traded instruments and over-the-counter instruments of various durations for the forward purchase or sale of our natural gas requirements, subject to regulatory approval or review. As a component of our gas costs, these expenses are subject to regulatory approval, and we may be exposed to additional liability if the recovery of these costs of gas supply procurement or risk management activities is excluded by our regulators in gas cost recovery proceedings.

*Operational interruptions to our gas distribution activities caused by accidents, work stoppage, severe weather such as a major hurricane, pandemic or acts of terrorism could adversely impact earnings.*

Inherent in our gas distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, mechanical problems and third party excavation damage. Weather events such as hurricanes, as well as acts of terrorism, can also damage our pipelines and other infrastructure and disrupt our ability to conduct our natural gas distribution and transportation business. Pandemic could result in a significant part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. If the foregoing events are severe enough or if they lead to operational interruptions, they could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental damage, impairment of our operations and substantial loss to us. The location of pipeline and storage facilities near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering places, could increase the level of damages resulting from these risks. Our regulators may not allow us to recover part or all of the increased cost related to the foregoing events from our customers, which would negatively affect our earnings. With part of our workforce represented by unions, we are exposed to the risk of a work stoppage. The occurrence of any of these events could adversely affect our financial position, results of operations and cash flows.

*Opposition to infrastructure development may delay or prevent us from expanding our business.*

In order to serve new customers or expand our service to existing customers, we often need to expand or upgrade our distribution, transmission and/or storage infrastructure, including laying new pipeline and building compressor stations or LNG storage tanks. Such infrastructure development requires us to seek approval from local, state and/or federal regulatory and governmental bodies. The approval process may involve the opportunity for the public to voice opposition. Such opposition may delay or prevent such development, or may make it materially more costly to do so. As a result, we may not be able to adequately support customer growth, which would negatively impact our earnings.

*A downgrade in our credit rating could negatively affect our cost of and ability to access capital.*

Our ability to obtain adequate and cost effective financing depends on our credit ratings. A negative change in our ratings outlook or any downgrade in our current investment-grade credit ratings by our rating agencies, particularly below investment grade, could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit our access to private credit markets and increase the costs of borrowing under available credit lines. Should our credit rating be downgraded, the interest rate on our borrowings under our revolving credit agreement would increase. An increase in borrowing costs without the recognition of these higher costs in the rates charged to our customers could adversely affect earnings by limiting our ability to earn our allowed rate of return.

*The inability to access capital or significant increases in the cost of capital could adversely affect our business.*

Our ability to obtain adequate and cost effective financing is dependent upon the liquidity of the financial markets, in addition to our credit ratings. Disruptions in the capital and credit markets could adversely affect our ability to access short-term and long-term capital. Our access to funds under short-term credit facilities is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Longer disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to capital needed for our business. The inability to access adequate capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate the dividend or other discretionary uses of cash.

*Changes in federal and state fiscal and monetary policy could significantly increase our costs.*

Changes in federal and state fiscal and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods and services. This could increase our expenses and decrease our earnings if such increased costs are not reflected in allowed rates charged to customers. This series of events may increase our rates to customers and thus may negatively impact customer billings and customer growth. Any of these events may negatively affect our ability to make capital expenditures to grow the business and negatively affect earnings.

*We do not generate sufficient cash flows to meet all our cash needs.*

Historically, we have made large capital expenditures in order to finance the expansion and upgrading of our distribution system. We have also purchased and will continue to purchase natural gas for storage. We have made several equity method investments and will continue to pursue other similar investments, all of which are and will be important to our profitability. Volatility in gas prices may require us to post cash collateral as part of our regulated gas price hedging program. We have funded a portion of our cash needs for these purposes, as well as contributions to our employee pensions and benefit plans, through borrowings under credit arrangements and by offering new securities in the open market. Our dependency on external sources of financing creates the risk that our profits could decrease as a result of higher borrowing costs and that we may not be able to secure external sources of cash necessary to fund our operations and new investments on terms acceptable to us. Volatility in seasonal cash flow requirements, including requirements for our gas supply procurement and risk management programs, may require increased levels of borrowing that could result in non-compliance with the debt-to-equity ratios in our credit facilities as well as cause a credit rating downgrade. Any disruptions in the capital and credit markets could require us to conserve cash until the markets stabilize or until alternative credit arrangements or other funding required for our needs can be secured. Such measures could cause deferral of major capital expenditures, changes in our gas supply procurement and risk management programs, the reduction or elimination of the dividend payment or other discretionary uses of cash.

*As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.*

The terms of our senior indebtedness, including our revolving credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under the indenture or other loan agreements. Accordingly, should an event of default occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to implement our business plan, make capital expenditures and finance our operations.

*Certain purchasers of our common stock under our dividend reinvestment and stock purchase plan (DRIP) may be entitled to rescind their purchases.*

As a result of an administrative error, sales of 568,000 shares of our common stock under the DRIP between December 1, 2008 and November 16, 2009, which represent less than 1% of our outstanding shares of common stock as of November 16, 2009, have not complied with the registration requirements of applicable securities laws, making them unregistered shares. A number of remedies may be available to DRIP participants who acquired shares during that period, including a right to rescind their purchases not later than one year after the date of the Form S-3 rescission offer to receive the full price paid by the DRIP participants, plus interest less any dividends received. DRIP participants who purchased unregistered shares pursuant to the DRIP and whose unregistered shares have fallen in value since the date of purchase could have an incentive to seek and to accept such a rescission. The sale of unregistered shares could also subject us to regulatory sanctions by the SEC or other regulatory authorities that might result in the imposition of civil penalties, which could include fines or a cease and desist order. We have reported these events and are cooperating with the relevant regulatory authorities, including the SEC and NCUC. Although we do not expect any rescissions or regulatory actions to have a material adverse effect on us, we are unable to predict the full consequences of these events and regulatory actions.

*We are exposed to credit risk of counterparties with whom we do business.*

Adverse economic conditions affecting, or financial difficulties of, counterparties with whom we do business could impair the ability of these counterparties to pay for our services or fulfill their contractual obligations. We depend on these counterparties to remit payments to fulfill their contractual obligations on a timely basis. Any delay or default in payment or failure of the counterparties to meet their contractual obligations could adversely affect our financial position, results of operations or cash flows.

*Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact our liquidity and results of operations.*

Our costs of providing for the non-contributory defined benefit pension plan are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, future government regulation and our required or voluntary contributions made to the plan. A significant decline in the value of investments that fund our pension plan, if not offset or mitigated by a decline in our liabilities, may significantly differ from or alter the values and actuarial assumptions used to calculate our future pension expense. A decline in the value of these investments could increase the expense of our pension plan, and we could be required to fund our plan with significant amounts of cash. Such cash funding obligations could have a material impact on our liquidity by reducing cash flows and could negatively affect results of operations.

*We are subject to numerous environmental laws and regulations that may require significant expenditures or increase operating costs.*

We are subject to numerous federal and state environmental laws and regulations affecting many aspects of our present and future operations. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and approvals. Compliance with these laws and regulations can require significant expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply may result in fines, penalties and injunctive measures affecting operating assets. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

*We are subject to new and existing pipeline safety and system integrity laws and regulations that may require significant expenditures or significantly increase operating costs.*

We are subject to new and existing pipeline safety and system integrity laws and regulations affecting various aspects of our present and future operations. These laws and regulations generally require us to enhance pipeline safety and system integrity by identifying and reducing pipeline risks. Compliance with these laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers. Furthermore, because the language in some of these laws and regulations is not prescriptive, there is a risk that an incorrect or inadequate interpretation of these laws and regulations may lead to a failure to comply. Such a failure for this or other reasons may result in fines, penalties or injunctive measures. All of the above could result in a material adverse effect on our business, results of operations or financial condition.

*An overall economic downturn could negatively impact our earnings.*

Weakening of economic activity in our markets could result in a loss of customers or a decline in customer additions and energy consumption which could adversely affect our revenues or restrict our future growth. It may become more difficult for customers to pay their gas bills, leading to slow collections and higher-than-normal levels of accounts receivable. This could increase our financing requirements and non-gas cost bad debt expense. Earnings and liquidity would be negatively affected, reducing our ability to grow the business.

*Our inability to attract and retain professional and technical employees could adversely impact our earnings.*

Our ability to implement our business strategy and serve our customers is dependent upon the continuing ability to employ talented professionals and attract and retain a technically skilled workforce. Without such a skilled workforce, our ability to provide quality service to our customers and meet our regulatory requirements will be challenged and this could negatively impact our earnings.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

All property included in the consolidated balance sheets in "Utility Plant" is owned by us and used in our regulated utility segment. This property consists of intangible plant, production plant, storage plant, transmission plant, distribution plant and general plant as categorized by natural gas utilities, with 94% of the total invested in utility distribution and transmission plant to serve our customers. We have approximately 2,600 miles of transmission pipelines up to 30 inches in diameter that connect our distribution systems with the transmission systems of our pipeline suppliers. We distribute natural gas through approximately 28,400 miles (three-inch equivalent) of distribution mains. The transmission pipelines and distribution mains are located on or under public streets and highways, or property owned by others, for which we have obtained the necessary legal rights to place and operate our facilities on such property. All of these properties are located in North Carolina, South Carolina and Tennessee. Utility Plant includes "Construction work in progress" which primarily represents distribution, transmission and general plant projects that have not been placed into service pending completion.

None of our property is encumbered and all property is in use except for "Plant held for future use" as classified in our consolidated balance sheets. The amount classified as plant held for future use relates to expenditures associated with the Robeson County LNG facility on which we deferred the development and construction in March 2009 based on revised growth projections.

We own or lease for varying periods our corporate headquarters building located in Charlotte, North Carolina and district and regional offices in the locations shown below. Lease payments for these various offices totaled $5.3 million for the year ended October 31, 2009.

| North Carolina | South Carolina | Tennessee |
|---|---|---|
| Burlington | Anderson | Nashville |
| Cary | Gaffney | |
| Charlotte | Greenville | |
| Elizabeth City | Spartanburg | |
| Fayetteville | | |
| Goldsboro | | |
| Greensboro | | |
| Hickory | | |
| High Point | | |
| Indian Trail | | |
| New Bern | | |
| Reidsville | | |
| Rockingham | | |
| Salisbury | | |
| Spruce Pine | | |
| Tarboro | | |
| Wilmington | | |
| Winston-Salem | | |

Property included in the consolidated balance sheets in "Other Physical Property" is owned by the parent company and one of its subsidiaries. The property owned by the parent company primarily consists of residential and commercial water heaters leased to natural gas customers. The property owned by the subsidiary is real estate. None of our other subsidiaries directly own property as their operations consist solely of participating in joint ventures as an equity member.

## Item 3. Legal Proceedings

We have only routine immaterial litigation in the normal course of business.

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

No matters were submitted to a vote of security holders during our fourth quarter ended October 31, 2009.

PART II

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

### Market Information

Our common stock (symbol PNY) is traded on the New York Stock Exchange (NYSE). The following table provides information with respect to the high and low sales prices from the NYSE Composite for each quarterly period for the years ended October 31, 2009 and 2008.

| 2009 | High | Low |
|---|---|---|
| Quarter ended: | | |
| January 31 | $ 33.92 | $ 24.77 |
| April 30 | 27.55 | 20.68 |
| July 31 | 25.50 | 21.65 |
| October 31 | 25.87 | 23.10 |

| 2008 | High | Low |
|---|---|---|
| Quarter ended: | | |
| January 31 | $ 27.98 | $ 24.01 |
| April 30 | 27.68 | 24.05 |
| July 31 | 27.95 | 25.00 |
| October 31 | 35.29 | 20.52 |

### Holders

As of December 11, 2009, our common stock was owned by 14,587 shareholders of record. A holder of record excludes the individual security owners whose shares are held in the name of an investment company.

### Dividends

The following table provides information with respect to quarterly dividends paid on common stock for the years ended October 31, 2009 and 2008. We expect that comparable cash dividends will continue to be paid in the future.

| 2009 | Dividends Paid Per Share |
|---|---|
| Quarter ended: | |
| January 31 | 26¢ |
| April 30 | 27¢ |
| July 31 | 27¢ |
| October 31 | 27¢ |

| 2008 | Dividends Paid Per Share |
|---|---|
| Quarter ended: | |
| January 31 | 25¢ |
| April 30 | 26¢ |
| July 31 | 26¢ |
| October 31 | 26¢ |

The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued, with those for the senior notes being the most restrictive. We cannot pay or declare any dividends or make any other distribution on any class of stock or make any investments in subsidiaries or permit any subsidiary to do any of the above (all of the foregoing being "restricted payments") except out of net earnings available for restricted payments. As of October 31, 2009, net earnings available for restricted payments were greater than retained earnings; therefore, our retained earnings were not restricted.

Recent Sale of Unregistered Securities

Between December 1, 2008 and November 16, 2009, we sold 568,000 shares of common stock under our dividend reinvestment and stock purchase plan (DRIP) at prices ranging from $21.59 to $31.56. On November 16, 2009, we discovered that the offer and sale of these shares of common stock under the DRIP during this period were not registered under applicable securities laws and were not exempt from registration under those laws, making them unregistered shares. We received $13.6 million in the aggregate from these sales, which was used for financing the construction of additions to our facilities and for general corporate purposes. To ensure compliance with the Securities Act of 1933, as amended, to provide a remedy to any DRIP participant aggrieved by the failure to register and to notify DRIP participants of their rights as generally prescribed by the applicable securities laws, we intend to file a registration statement on Form S-3 to register a rescission offer to DRIP participants for the unregistered shares and to register the unregistered shares. The sale of unregistered shares could also subject us to regulatory sanctions by the Securities and Exchange Commission (SEC) or other regulatory authorities that might result in the imposition of civil penalties, which could include fines or a cease and desist order. We have reported these events and are cooperating with the relevant regulatory authorities, including the SEC and the North Carolina Utilities Commission (NCUC). Although we do not expect any rescissions or regulatory actions to have a material adverse effect on us, we are unable to predict the full consequences of these events and regulatory actions.

Share Repurchases

The following table provides information with respect to repurchases of our common stock under the Common Stock Open Market Purchase Program during the three months ended October 31, 2009.

| Period | Total Number of Shares Purchased (2) | Average Price Paid Per Share | Total Number of Shares Purchased as Part of Publicly Announced Program | Maximum Number of Shares that May Yet be Purchased Under the Program (1) |
|---|---|---|---|---|
| Beginning of the period | | | | 6,310,074 |
| 8/1/09 - 8/31/09 | - | $ - | - | 6,310,074 |
| 9/1/09 - 9/30/09 | 6,458 | $ 24.24 | - | 6,310,074 |
| 10/1/09 - 10/31/09 | - | $ - | - | 6,310,074 |
| Total | 6,458 | $ 24.24 | - | |

(1) The Common Stock Open Market Purchase Program was approved by the Board of Directors and announced on June 4, 2004 to purchase up to three million shares of common stock for reissuance under our dividend reinvestment and stock purchase, employee stock purchase and incentive compensation plans. On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the two-for-one stock split in 2004. The Board also approved on that date an amendment of the Common Stock Open Market Purchase Program to provide for the purchase of up to four million additional shares of common stock to maintain our debt-to-equity capitalization ratios at target levels. These combined actions increased the total authorized share repurchases from three million to ten million shares. The additional four million shares are referred to as our accelerated share repurchase program (ASR). On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated.

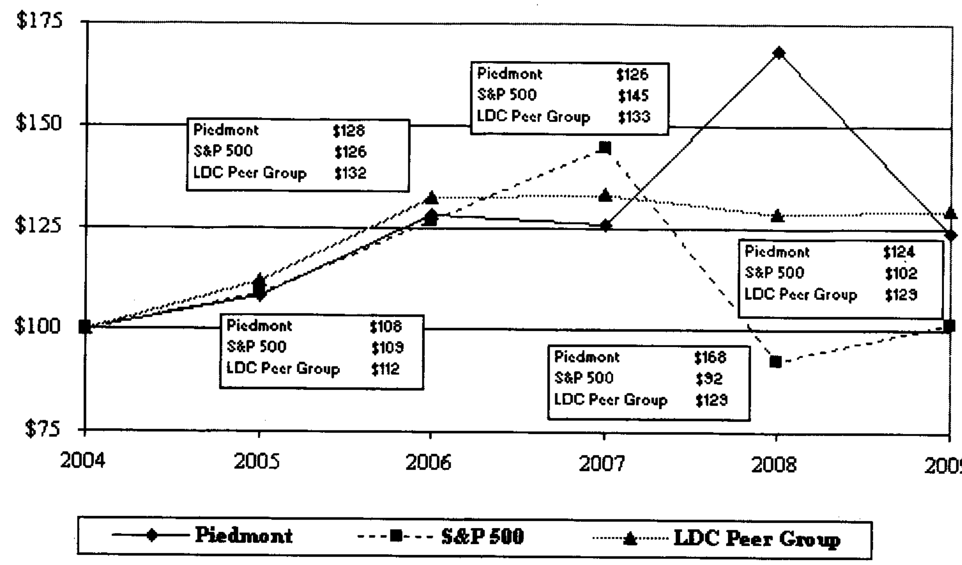
(2) The total number of shares purchased is shares withheld by us to satisfy tax withholding obligations related to the vesting of shares of restricted stock under an incentive compensation plan, which are outside of the Common Stock Open Market Purchase Program.

## Comparisons of Cumulative Total Shareholder Returns

The following performance graph compares our cumulative total shareholder return from October 31, 2004 through October 31, 2009 (a five-year period), with the Standard & Poor's 500 Stock Index, a broad market index (the S&P 500) and with our utility peer group. Large natural gas distribution companies that are representative of our peers in the natural gas distribution industry are included in our LDC Peer Group index.

The graph assumes that the value of an investment in Common Stock and in each index was $100 at October 31, 2004 and that all dividends were reinvested. Stock price performances shown on the graph are not indicative of future price performance.

Comparisons of Five-Year Cumulative Total Returns
Value of $100 Invested as of October 31, 2004




LDC Peer Group—The following companies are included: AGL Resources Inc., Atmos Energy Corporation, New Jersey Resources Corporation, NICOR Inc., NiSource Inc., Northwest Natural Gas Company, Southwest Gas Corporation, Vectren Corporation and WGL Holdings, Inc.

## Item 6. Selected Financial Data

The following table provides selected financial data for the years ended October 31, 2005 through 2009.

| In thousands except per share amounts | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| Operating Revenues | $ 1,638,116 | $ 2,089,108 | $ 1,711,292 | $ 1,924,628 | $ 1,761,091 |
| Margin (operating revenues less cost of gas) | $ 561,574 | $ 552,973 | $ 524,165 | $ 523,479 | $ 499,139 |
| Net Income | $ 122,824 | $ 110,007 | $ 104,387 | $ 97,189 | $ 101,270 |
| Earnings per Share of Common Stock: | | | | | |
| Basic | $ 1.68 | $ 1.50 | $ 1.41 | $ 1.28 | $ 1.32 |
| Diluted | $ 1.67 | $ 1.49 | $ 1.40 | $ 1.28 | $ 1.32 |
| Cash Dividends per Share of Common Stock | $ 1.070 | $ 1.030 | $ 0.990 | $ 0.950 | $ 0.905 |
| Total Assets * | $ 3,118,819 | $ 3,138,401 | $ 2,823,106 | $ 2,743,826 | $ 2,611,117 |
| Long-Term Debt (less current maturities) | $ 732,512 | $ 794,261 | $ 824,887 | $ 825,000 | $ 625,000 |

* Total assets for the years 2005 through 2008 have been adjusted to reflect the gross presentation rather than a net presentation in accordance with the adoption of new accounting guidance. See Note 14 to the consolidated financial statements.

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

### Forward-Looking Statements

This report, as well as other documents we file with the SEC, may contain forward-looking statements. In addition, our senior management and other authorized spokespersons may make forward-looking statements in print or orally to analysts, investors, the media and others. These statements are based on management's current expectations and information currently available and are believed to be reasonable and are made in good faith. However, the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those projected in the statements. Factors that may make the actual results differ from anticipated results include, but are not limited to:

- Regulatory issues affecting us and those from whom we purchase natural gas transportation and storage service, including those that affect allowed rates of return, terms and conditions of service, rate structures and financings. We monitor our ability to earn appropriate rates of return and initiate general rate proceedings as needed.

- Residential, commercial, industrial and power generation growth and energy consumption in our service areas. The ability to grow our customer base, the pace of that growth and the levels of energy consumption are impacted by general business and economic conditions, such as interest rates, inflation, fluctuations in the capital markets and the overall strength of the economy in our service areas and the country, and fluctuations in the wholesale prices of natural gas and competitive energy sources.

- Deregulation, regulatory restructuring and competition in the energy industry. We face competition from electric companies and energy marketing and trading companies, and we expect this competitive environment to continue.

- The potential loss of large-volume industrial customers to alternate fuels or to bypass, or the shift by such customers to special competitive contracts or to tariff rates that are at lower per-unit margins than that customer's existing rate.

- The capital-intensive nature of our business. In order to maintain growth, we must add to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining governmental approvals, compliance with federal and state pipeline safety and integrity regulations, development project delays and the cost and availability of labor and materials. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost and timing of a project.

- Access to capital markets. Our internally generated cash flows are not adequate to finance the full cost of capital expenditures. As a result, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations. Changes in the capital markets or our financial condition could affect access to and cost of capital.

- Changes in the availability and cost of natural gas. To meet firm customer requirements, we must acquire sufficient gas supplies and pipeline capacity to ensure delivery to our distribution system while also ensuring that our supply and capacity contracts allow us to remain competitive. Natural gas is an unregulated commodity market subject to supply and demand and price volatility. Producers, marketers and pipelines are subject to operating, regulatory and financial risks associated with exploring, drilling, producing, gathering, marketing and transporting natural gas and have risks that increase our exposure to supply and price fluctuations. Since such risks may affect the availability and cost of natural gas, they also may affect the competitive position of natural gas relative to other energy sources.

- Changes in weather conditions. Weather conditions and other natural phenomena can have a material impact on our earnings. Severe weather conditions, including destructive weather patterns such as hurricanes, can impact our suppliers and the pipelines that deliver gas to our distribution system. Weather conditions directly influence the supply of, demand for and the cost of natural gas.

- Changes in environmental, safety, system integrity, tax and other laws and regulations, including climate change legislation, and the cost of compliance. We are subject to extensive federal, state and local laws and regulations. Compliance with such laws and regulations could increase capital or operating costs, affect our reported earnings, increase our liabilities or change the way our business is conducted.

- Ability to retain and attract professional and technical employees. To provide quality service to our customers and meet regulatory requirements, we are dependent on our ability to recruit, train, motivate and retain qualified employees.

- Changes in accounting regulations and practices. We are subject to accounting regulations and practices issued periodically by accounting standard-setting bodies. New accounting standards may be issued that could change the way we record revenues, expenses, assets and liabilities, and could affect our reported earnings or increase our liabilities.

- Earnings from our equity method investments. We invest in companies that have risks that are inherent in their businesses, and these risks may negatively affect our earnings from those companies.

- Changes in outstanding shares. The number of outstanding shares may fluctuate due to repurchases under our Common Stock Open Market Purchase Program or new issuances.

Other factors may be described elsewhere in this report. All of these factors are difficult to predict and many of them are beyond our control. For these reasons, you should not rely on these forward-looking statements when making investment decisions. When used in our documents or oral presentations, the words “expect,” “believe,” “project,” “anticipate,” “intend,” “should,” “could,” “will,” “assume,” “can,” “estimate,” “forecast,” “future,” “indicate,” “outlook,” “plan,” “predict,” “seek,” “target,” “would” and variations of such words and similar expressions are intended to identify forward-looking statements.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update publicly any forward-looking statement either as a result of new information, future events or otherwise except as required by applicable laws and regulations. Please reference our website at www.piedmontng.com for current information. Our reports on Form 10-K, Form 10-Q and Form 8-K and amendments to these reports are available at no cost on our website as soon as reasonably practicable after the report is filed with or furnished to the SEC.

Executive Overview

Piedmont Natural Gas Company, Inc., which began operations in 1951, is an energy services company whose principal business is the distribution of natural gas to over one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 61,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.

In 1994, our predecessor, which was incorporated in 1950 under the same name, was merged into a newly formed North Carolina corporation for the purpose of changing our state of incorporation to North Carolina.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We provide service to Anderson, Gaffney, Greenville and Spartanburg in South Carolina and Charlotte, Salisbury, Greensboro, Winston-Salem, High Point, Burlington, Hickory, Indian Trail, Spruce Pine, Reidsville, Fayetteville, New Bern, Wilmington, Tarboro, Elizabeth City, Rockingham and Goldsboro in North Carolina. In North Carolina, we also provide wholesale natural gas service to Greenville, Monroe, Rocky Mount and Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to Gallatin and Smyrna.

We have two reportable business segments, regulated utility and non-utility activities. The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. Factors critical to the success of the regulated utility include a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in rates charged to customers. For the year ended October 31, 2009, 84% of our earnings before taxes came from our regulated utility segment. The non-utility activities segment consists of our equity method investments in joint venture, energy-related businesses that are involved in unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. For the year ended October 31, 2009, the earnings before taxes from our non-utility segment was 16%, which consisted of 4% from regulated non-utility activities and 12% from unregulated non-utility activities. For further information on business segments, see Note 12 to the consolidated financial statements. For information about our equity method investments, see Note 11 to the consolidated financial statements.

Our utility operations are regulated by the NCUC, the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are also regulated by the NCUC as to the issuance of securities. We are also subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the Federal Energy Regulatory Commission (FERC) that affect the purchase and sale of and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. In addition, we are subject to numerous regulations, such as those relating to employment practices, which are generally applicable to companies doing business in the United States of America.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection of margin or recover any under-collection of margin. We have weather normalization adjustment (WNA) mechanisms in South Carolina and Tennessee that partially offset the impact of colder- or warmer-than-normal weather on bills rendered during the months of November through March for residential and commercial customers. The WNA formula calculates the actual weather variance from normal, using 30 years of history, which results in an increase in revenues when weather is warmer than normal and a decrease in revenues when weather is colder than normal. The gas cost portion of our costs is recoverable through purchased gas adjustment (PGA) procedures and is not affected by the margin decoupling mechanism or the WNA. For further information, see Note 2 to the consolidated financial statements.

Our strategic focus is on our core business of providing safe, reliable and quality natural gas distribution service to our customers in the growing Southeast market area. Part of our strategic plan is to responsibly manage our gas distribution business through control of our operating costs, implementation of new technologies and sound rate and regulatory initiatives. We are working to enhance the value and growth of our utility assets by good management of capital spending, including improvements for current customers, and the pursuit of profitable customer growth opportunities in our service areas. We strive for quality customer service by investing in technology, processes and people. We work with our state regulators to maintain fair rates of return and balance the interests of our customers and shareholders.

We seek to maintain a long-term debt-to-capitalization ratio within a range of 45% to 50%. We also seek to maintain a strong balance sheet and investment-grade credit ratings to support our operating and investment needs.

With the combination of the global recession and the movement to implement climate change policies that will impact how energy is used in this country, we are working toward a business model that positions us for long-term success in a carbon-constrained energy economy. This includes continual assessment of the nature of our business and examination of alternative cost recovery mechanisms and rate structures that are more appropriate in a changing energy economy. Additionally, we are seeking opportunities for regulatory innovation and strategic alliances to advance our customers' interests in energy conservation and efficiency and environmental stewardship.

One of our 2009 objectives has been to focus on future growth opportunities in a low-carbon energy economy. We are continually reviewing our business processes for quality and efficiency with a concentration on customer-oriented process improvements. We will continue this focus to be in a position to seize future business opportunities.

We must leverage our regulatory structure to realize future growth opportunities in a low-carbon energy economy. One example of this is our pursuit of alternatives to the traditional utility rate design that provide for the collection of margin revenue based on volumetric throughput with new rate designs and incentives that allow utilities to encourage energy efficiency and conservation. By breaking the link between energy consumption and margin revenues, or decoupling as we say, utilities' interests are aligned with customers' interests around conservation and energy efficiency. In North Carolina, we have decoupled rates. In South Carolina, we operate under a rate stabilization mechanism that achieves the objectives of margin decoupling with a one-year lag. In Tennessee, we have filed to decouple our rates; that filing has been contested by the state Attorney General and went to hearing on December 17 – 18, 2009.

Even as we implement energy efficiency programs for our customers so that individual residential and business customers can save on their total natural gas bill by using natural gas as efficiently as possible, we also will continue our efforts to promote the direct use of natural gas in more homes, businesses, industries and vehicles. Our message is simple: the expanded use of domestic natural gas can help revitalize our economy, reduce overall greenhouse gas emissions and enhance our national energy security. Recent production of domestic natural gas supplies from shale formations has resulted in an increase of supply, which in turn has contributed to a moderation in the price of gas. This price moderation, if it continues as many in the industry anticipate, should lead to an increase in the competitiveness of natural gas as compared to other fuels.

One example is our October 2009 announcement of an agreement with Progress Energy Carolinas, Inc., a subsidiary of Progress Energy, Inc., to provide natural gas delivery service to a new power generation facility to be built at their Wayne County, North Carolina power generation site. In addition to the environmental benefits associated with using natural gas at this new plant, the construction of the natural gas pipeline for this project will also add to our natural gas infrastructure in the eastern part of North Carolina and enhance future opportunities for additional economic growth and development.

We are seeing the impacts of the economic recession in our market area with a decline in customer growth in our new construction market and continued customer conservation practices. While we have also experienced a decline in margin in our commercial and industrial markets from lower energy consumption related to company closings and reduced production and business activities, we have recently seen some rebound in these markets. As discussed above, we are positioning ourselves to capitalize on new opportunities as the economy improves.

The decline in gross residential and commercial customer additions was 39% from 2008. To mitigate this, we are actively seeking customer conversions to natural gas in order to gain new customers outside of the new construction market.

Earlier this year, we deferred the development and construction of our previously announced liquefied natural gas (LNG) peak storage facility in Robeson County, North Carolina based on growth projections at that time. Our current growth projections indicate that we may need to resume development of the project in 2011 to prepare for construction in 2012 in order to provide service in 2015. With the uncertain economic outlook and recovery, we will continue to monitor customer growth trends in our markets and plan for the development of this project and other infrastructure projects when needed to meet future customer requirements.

Under current economic conditions, it has become more difficult for some customers to pay their gas bills, leading to slower collections and higher non-gas bad debt expense. With a slower turnover of accounts receivable, our level of borrowings could increase in order to meet our working capital needs. This series of events may be mitigated by the expectation of lower gas prices for the 2009-2010 heating season as lower natural gas prices were realized in 2009.

We invest in joint ventures to complement or supplement income from our regulated utility operations if an opportunity aligns with our overall business strategies and allows us to leverage our core competencies. We analyze and evaluate potential projects with a major factor being a projected rate of return greater than the returns allowed in our utility operations due to the higher risk of such projects. We participate in the governance of our ventures by having management representatives on the governing boards. We monitor actual performance against expectations, and any decision to exit an existing joint venture would be based on many factors, including performance results and continued alignment with our business strategies. We have entered into an agreement to sell half of our 30% interest in SouthStar Energy Services LLC (SouthStar) to Georgia Natural Gas Company (GNGC) for $57.5 million to be effective January 1, 2010. For further information, see Note 11 to the consolidated financial statements.

Results of Operations

The following tables present our financial highlights for the years ended October 31, 2009, 2008 and 2007.

Income Statement Components

| In thousands except per share amounts | 2009 | 2008 | 2007 | Percent Change 2009 vs. 2008 | Percent Change 2008 vs. 2007 |
|---|---|---|---|---|---|
| Operating Revenues | $ 1,638,116 | $ 2,089,108 | $ 1,711,292 | (21.6)% | 22.1 % |
| Cost of Gas | 1,076,542 | 1,536,135 | 1,187,127 | (29.9)% | 29.4 % |
| Margin | 561,574 | 552,973 | 524,165 | 1.6 % | 5.5 % |
| Operations and Maintenance | 208,105 | 210,757 | 214,442 | (1.3)% | (1.7)% |
| Depreciation | 97,425 | 93,121 | 88,654 | 4.6 % | 5.0 % |
| General Taxes | 34,590 | 33,170 | 32,407 | 4.3 % | 2.4 % |
| Income Taxes | 70,079 | 62,814 | 51,315 | 11.6 % | 22.4 % |
| Total Operating Expenses | 410,199 | 399,862 | 386,818 | 2.6 % | 3.4 % |
| Operating Income | 151,375 | 153,111 | 137,347 | (1.1)% | 11.5 % |
| Other Income (Expense), net of tax | 18,124 | 16,169 | 24,312 | 12.1 % | (33.5)% |
| Utility Interest Charges | 46,675 | 59,273 | 57,272 | (21.3)% | 3.5 % |
| Net Income | $ 122,824 | $ 110,007 | $ 104,387 | 11.7 % | 5.4 % |
| Average Shares of Common Stock: | | | | | |
| Basic | 73,171 | 73,334 | 74,250 | (0.2)% | (1.2)% |
| Diluted | 73,461 | 73,612 | 74,472 | (0.2)% | (1.2)% |
| Earnings per Share of Common Stock: | | | | | |
| Basic | $ 1.68 | $ 1.50 | $ 1.41 | 12.0 % | 6.4 % |
| Diluted | $ 1.67 | $ 1.49 | $ 1.40 | 12.1 % | 6.4 % |

Gas Deliveries, Customers, Weather Statistics and Number of Employees

| | 2009 | 2008 | 2007 | Percent Change 2009 vs. 2008 | Percent Change 2008 vs. 2007 |
|---|---|---|---|---|---|
| Deliveries in Dekatherms (in thousands): | | | | | |
| Sales Volumes | 110,379 | 110,801 | 105,606 | (0.4)% | 4.9 % |
| Transportation Volumes | 106,495 | 99,450 | 100,398 | 7.1 % | (0.9)% |
| Throughput | 216,874 | 210,251 | 206,004 | 3.2 % | 2.1 % |
| Secondary Market Volumes | 46,057 | 53,442 | 42,049 | (13.8)% | 27.1 % |
| Customers Billed (at period end) | 937,962 | 935,724 | 922,961 | 0.2 % | 1.4 % |
| Gross Customer Additions | 12,608 | 20,506 | 30,437 | (38.5)% | (32.6)% |
| Degree Days | | | | | |
| Actual | 3,413 | 3,195 | 2,977 | 6.8 % | 7.3 % |
| Normal | 3,324 | 3,358 | 3,388 | (1.0)% | (0.9)% |
| Percent colder (warmer) than normal | 2.7 % | (4.9)% | (12.1)% | n/a | n/a |
| Number of Employees (at period end) | 1,821 | 1,833 | 1,876 | (0.7)% | (2.3)% |

## Net Income

Net income increased $12.8 million in 2009 compared with 2008 primarily due to the following changes which increased net income:

- $12.6 million decrease in utility interest charges.

- $8.6 million increase in margin (operating revenues less cost of gas).
- $5.7 million increase in income from equity method investments.
- $2.7 million decrease in operations and maintenance expenses.

These changes were partially offset by the following changes which decreased net income:

- $ 8.4 million increase in income taxes.
- $4.3 million increase in depreciation.
- $2.7 million decrease in net other income (expense) items.
- $1.4 million increase in general taxes.

Net income increased $5.6 million in 2008 compared with 2007 primarily due to the following changes which increased net income:

- $28.8 million increase in margin.
- $3.7 million decrease in operations and maintenance expenses, primarily due to lower pension expense accruals due to the restructuring of our defined benefit pension program.

These changes were partially offset by the following changes which decreased net income:

- $9.4 million decrease in earnings from equity method investments.
- $7.9 million increase in income taxes.
- $4.5 million increase in depreciation.
- $2.3 million decrease in net other income (expense) items.
- $2 million increase in utility interest charges.
- $.8 million increase in general taxes.

Operating Revenues

Operating revenues in 2009 decreased $451 million compared with 2008 primarily due to the following decreases:

- $294.7 million from revenues in secondary market transactions due to decreased activity and gas costs. Secondary market transactions consist of off-system sales and capacity release arrangements and are part of our regulatory gas supply management program with regulatory-approved sharing mechanisms between our utility customers and our shareholders.
- $112.1 million primarily from lower gas costs passed through to sales customers.
- $19.4 million from revenues under the margin decoupling mechanism. As discussed in "Financial Condition and Liquidity," the margin decoupling mechanism in North Carolina adjusts for variations in residential and commercial use per customer, including those due to conservation and weather.
- $12.7 million of commodity gas costs from decreased volume deliveries to sales customers.
- $8 million from revenues under the WNA in South Carolina and Tennessee.

- $5.4 million from a decrease in volumes delivered to transportation customers other than power generation.

Operating revenues in 2008 increased $377.8 million compared with 2007 primarily due to the following increases:

- $207.1 million from revenues in secondary market transactions due to increased activity and higher gas costs.
- $143.7 million primarily from increased commodity and demand costs passed through to sales customers.
- $29.3 million of commodity gas costs from higher volume deliveries to sales customers.

These increases were partially offset by a $7.3 million decrease from revenues under the margin decoupling mechanism.

Cost of Gas

Cost of gas in 2009 decreased $459.6 million compared with 2008 primarily due to the following decreases:

- $294.2 million from commodity gas costs in secondary market transactions due to decreased activity and gas costs.
- $127.2 million primarily from lower gas costs passed through to sales customers.
- $12.7 million of commodity gas costs from decreased volume deliveries to sales customers.

Cost of gas in 2008 increased $349 million compared with 2007 primarily due to the following increases:

- $207.7 million from commodity gas costs in secondary market transactions due to increased activity and higher gas costs.
- $111.9 million from increased commodity and demand costs passed through to sales customers.
- $29.3 million of commodity gas costs from higher volume deliveries to sales customers.

In all three states, we are authorized to recover from customers all prudently incurred gas costs. Changes to cost of gas are based on the amount recoverable under approved rate schedules. The net of any over- or under-recoveries of gas costs are reflected in a regulatory deferred account and are added to or deducted from cost of gas and are included in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets.

Margin

Our utility margin is defined as natural gas revenues less natural gas commodity purchases and fixed gas costs for transportation and storage capacity. Margin, rather than revenues, is used by management to evaluate utility operations due to the impact of volatile wholesale commodity prices, which accounts for 52% of revenues for the twelve months ended October 31, 2009, and transportation and storage costs, which account for 8%.

In general rate proceedings, state regulatory commissions authorize us to recover a margin, which is the applicable billing rate less cost of gas, on each unit of gas delivered. The commissions also authorize us to recover margin losses resulting from negotiating lower rates to industrial customers when necessary to remain competitive. The ability to recover such negotiated margin reductions is subject to continuing regulatory approvals.

Our utility margin is also impacted by certain regulatory mechanisms as defined elsewhere in this document. These include the WNA in Tennessee and South Carolina, the Natural Gas Rate Stabilization Act (RSA) in South Carolina, secondary market activity in North Carolina and South Carolina, the Tennessee Incentive Plan (TIP) in Tennessee, the margin decoupling mechanism in North Carolina and negotiated loss treatment and the collection of uncollectible gas costs in all three jurisdictions. We retain 25% of secondary market margins generated through off-system sales and capacity release activity in all jurisdictions, with 75% credited to customers through the incentive plans.

Margin increased $8.6 million in 2009 compared with 2008 primarily due to an increase of $15.7 million from increased rates approved in the North Carolina general rate case effective November 1, 2008.

This increase was partially offset by the following decreases:

- $4.7 million from net adjustments to gas costs, inventory, supplier refunds and lost and unaccounted for gas due to regulatory gas cost reviews.
- $2.9 million from decreased volumes delivered to industrial customers.

Margin increased $28.8 million in 2008 compared with 2007 primarily due to the following increases:

- $12.8 million from period to period net adjustments to gas costs, inventory, supplier refunds and lost and unaccounted for gas due to regulatory gas cost accounting reviews.
- $11.3 million from growth in our residential and commercial customer base.
- $5.4 million from the regulatory ruling that discontinued the capitalizing and amortizing of storage demand charges effective November 1, 2007.

These increases were partially offset by a $.9 million decrease from lower sales volumes in our power generation market.

Operations and Maintenance Expenses

Operations and maintenance expenses decreased $2.7 million in 2009 compared with 2008 primarily due to the following decreases:

- $3.6 million in employee benefits expense due to reductions in pension expense resulting from changes in the discount rate and plan design, regulatory deferral of the Tennessee portion of the annual plan funding and lower group insurance expense from

claims experience, and fewer employees.
- $1.4 million in contract labor for contract billing services, telecom and financial, gas accounting and compliance systems.

These decreases were partially offset by an increase of $2.7 million in regulatory amortization expense.

Operations and maintenance expenses decreased $3.7 million in 2008 compared with 2007 primarily due to the following decreases:

- $9.1 million in employee benefits expense due to reductions in pension expense resulting from changes in plan design and lower group insurance expense from claims experience, and fewer employees.
- $1 million in office supplies due to customer billing outsourcing which resulted in reduced postage and billing supply expenses.
- $.6 million in transportation costs primarily due to fewer vehicles being used as a result of our automated meter reading initiative and other fleet management efforts.

These decreases were partially offset by the following increases:

- $3.6 million in payroll expense primarily due to an increase in long-term incentive plan accruals in 2008 because of a higher share price and performance levels, partially offset by the impact of fewer employees.
- $2.3 million in contract labor primarily due to contract billing services, telecom and financial, gas accounting and compliance systems.
- $.5 million in utilities primarily due to increased charges for measurement systems.
- $.5 million in advertising.

Depreciation

Depreciation expense increased from $88.7 million to $97.4 million over the three-year period 2007 to 2009 primarily due to increases in plant in service.

General Taxes

General taxes increased $1.4 million in 2009 compared with 2008 primarily due to increases in property taxes related to a larger property tax base and reassessments.

General taxes increased $.8 million in 2008 compared with 2007 primarily due to the following changes:

- $.6 million increase in property taxes related to a refund for South Carolina taxes in the prior year.
- $.4 million increase in gross receipts taxes in Tennessee.
- $.2 million decrease in payroll taxes primarily related to organizational restructuring and process improvement initiatives that began in 2007, partially offset by an increase in the social security wage limit.

Other Income (Expense)

Other Income (Expense) is comprised of income from equity method investments, non-operating income, charitable contributions, non-operating expense and income taxes related to these items. Non-operating income includes non-regulated merchandising and service work, subsidiary operations, interest income and other miscellaneous income. Non-operating expense is comprised of other miscellaneous expenses.

The primary changes to Other Income (Expense) were in income from equity method investments discussed below. All other changes were not significant.

Income from equity method investments increased $5.7 million in 2009 compared with 2008 primarily due to an increase of $6.3 million in earnings from SouthStar largely due to higher contributions from the management of storage and transportation assets, margin impacts from lower of cost or market inventory adjustments, higher operating margins in Ohio, a 2008 pricing settlement with the Georgia Public Service Commission (Georgia PSC) and increased average customer usage, partially offset by a change in retail pricing plan mix and a decrease in the average number of customers.

Income from equity method investments decreased $9.4 million in 2008 compared with 2007 primarily due to the following changes:

- $9.9 million decrease in earnings from SouthStar primarily due to lower of cost or market inventory adjustments, lower contributions from the management of storage and transportation assets, a loss on weather derivatives and a Georgia PSC consent agreement related to retail pricing.
- $.9 million increase in earnings from Hardy Storage Company, LLC (Hardy Storage) primarily due to its first full year of operations, partially offset by higher operations and maintenance expenses, depreciation and general taxes.

Utility Interest Charges

Utility interest charges decreased $12.6 million in 2009 compared with 2008 primarily due to the following changes:

- $9.1 million decrease in net interest expense due to an increase in interest earned on amounts due from customers in the current period.
- $4.7 million decrease in interest on short-term debt primarily due to the average interest rates during the current period being 290 basis points lower than the prior year period even though borrowings were higher in the current period.
- $1.7 million increase in the allowance for borrowed funds.

Utility interest charges increased $2 million in 2008 compared with 2007 primarily due to the following changes:

- $2.7 million increase in regulatory interest expense primarily due to interest true-ups related to amounts due to customers.
- $.3 million increase in interest on short-term debt due to higher balances outstanding.

- $.9 million decrease in interest expense related to a federal tax audit settlement in 2007.
- $.3 million decrease in interest on regulatory treatment of certain components of deferred income taxes.

Financial Condition and Liquidity

To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, cash generated from our investments in joint ventures and short-term bank borrowings. Even though we have been operating in tighter credit markets for over a year, we believe that these sources, including amounts available to us under our existing credit facility, will continue to allow us to meet our needs for working capital, construction expenditures, investments in joint ventures, anticipated debt redemptions and dividend payments.

Cash Flows from Operating Activities. The natural gas business is seasonal in nature. Operating cash flows may fluctuate significantly during the year and from year to year due to working capital changes within our utility and non-utility operations resulting from such factors as weather, natural gas purchases and prices, natural gas storage activity, collections from customers and deferred gas cost recoveries. We rely on operating cash flows and short-term bank borrowings to meet seasonal working capital needs. During our first and second quarters, we generally experience overall positive cash flows from the sale of flowing gas and gas in storage and the collection of amounts billed to customers during the winter heating season (November through March). Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases for storage, seasonal construction activity and decreases in receipts from customers.

During the winter heating season, our accounts payable increase to reflect amounts due to our natural gas suppliers for commodity and pipeline capacity. The cost of the natural gas can vary significantly from period to period due to volatility in the price of natural gas, which is a function of market fluctuations in the price of natural gas, along with our changing requirements for storage volumes. Differences between natural gas costs that we have paid to suppliers and amounts that we have collected from customers are included in regulatory deferred accounts and in amounts due to/from customers. These natural gas costs can cause cash flows to vary significantly from period to period along with variations in the timing of collections from customers under our gas cost recovery mechanisms.

Cash flows from operations are impacted by weather, which affects gas purchases and sales. Warmer weather can lead to lower revenues from fewer volumes of natural gas sold or transported. Colder weather can increase volumes sold to weather-sensitive customers, but may lead to conservation by customers in order to reduce their heating bills. Warmer-than-normal weather can lead to reduced operating cash flows, thereby increasing the need for short-term bank borrowings to meet current cash requirements.

Because of the economic recession, we may incur additional bad debt expense during the winter heating season, as well as experience increased customer conservation. We may incur more short-term debt to pay for gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their bills. Regulatory margin stabilizing and cost recovery mechanisms, such as those that allow us to recover the gas cost portion of bad debt expense, will significantly mitigate the impact these factors may have on our results of operations.

Net cash provided by operating activities was $344.3 million in 2009, $69.2 million in 2008 and $233.5 million in 2007. Net cash provided by operating activities reflects a $12.8 million increase in net income for 2009 compared with 2008. The effect of changes in working capital on net cash provided by operating activities is described below:

- Trade accounts receivable and unbilled utility revenues decreased $29.3 million in the current period primarily due to the decrease in unbilled volumes and amounts billed to customers reflecting lower gas costs in 2009 as compared with 2008, partially offset by weather in the current period being 7% colder than the same prior period. Volumes sold to residential and commercial customers increased 5.1 million dekatherms as compared with the same prior period primarily due to the colder weather. Total throughput increased 6.6 million dekatherms as compared with the same prior period.
- Net amounts due from customers increased $14.4 million in the current period primarily resulting from realized and unrealized losses on hedging activities, partially offset by decreases for gas cost differences deferred and the impact of the decrease in amounts recorded under the margin decoupling mechanism.
- Gas in storage decreased $86.7 million in the current period primarily due to a decrease in the average cost of gas in storage as well as decreased volumes in storage in 2009 as compared with 2008.
- Prepaid gas costs decreased $37.2 million in the current period primarily due to the lower average cost of gas in prepaid storage. Prepaid gas costs represent purchases of gas during the summer months under gas supply contracts that are not available for sale, and therefore not recorded in inventory, until the winter heating season.
- Trade accounts payable decreased $25.4 million in the current period primarily due to gas purchases at lower costs during the fourth quarter.

Our three state regulatory commissions approve rates that are designed to give us the opportunity to generate revenues to cover our gas costs, fixed and variable non-gas costs and earn a fair return for our shareholders. We have a WNA mechanism in South Carolina and Tennessee that partially offsets the impact of colder- or warmer-than-normal weather on bills rendered in November through March for residential and commercial customers. The WNA in South Carolina and Tennessee generated credits to customers of $1.2 million in 2009, and charges of $6.8 million in 2008 and $6.4 million in 2007. In Tennessee, adjustments are made directly to individual customer bills. In South Carolina, the adjustments are calculated at the individual customer level but are recorded in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets for subsequent collection from or refund to all customers in the class. The margin decoupling mechanism in North Carolina provides for the collection of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism increased margin by $6 million in 2009, $25.4 million in 2008 and $32.7 million in 2007. Our gas costs are recoverable through PGA procedures and are not affected by the WNA or the margin decoupling mechanism.

The financial condition of the natural gas marketers and pipelines that supply and deliver natural gas to our distribution system can increase our exposure to supply and price fluctuations. We believe our risk exposure to the financial condition of the marketers and pipelines is not significant based on our receipt of the products and services prior to payment and the availability of other marketers of natural gas to meet our firm supply needs if necessary. We have regulatory commission approval in North Carolina, South Carolina and Tennessee that places tighter credit requirements on the retail natural gas marketers that schedule gas for transportation service on our system.

The regulated utility competes with other energy products, such as electricity and propane, in the residential and commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. Numerous factors can influence customer demand for natural gas, including price, value, availability, environmental attributes, reliability and energy efficiency. Increases in the price of natural gas can negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This can impact our cash needs if customer growth slows, resulting in reduced capital expenditures, or if customers conserve, resulting in reduced gas purchases and customer billings.

In the industrial market, many of our customers are capable of burning a fuel other than natural gas, with fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on price. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the US dollar versus other currencies. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

In an effort to keep customer rates competitive and to maximize earnings, we continue to implement business process improvement and operations and maintenance cost management programs to capture operational efficiencies while improving customer service and maintaining a safe and reliable system.

In July 2009, we reached an agreement with GNGC to sell half of our 30% membership interest in SouthStar to GNGC, effective January 1, 2010, retaining a 15% earnings and membership share in SouthStar after the sale. Currently, earnings and losses are allocated to us at 25% with the exception of earnings and losses in the Ohio and Florida markets, which are allocated to us at our membership percentage of 30%. At closing, we will receive $57.5 million from GNGC resulting in an estimated after-tax gain of $30 million in 2010, or $.42 per diluted share. The agreement was approved by the Georgia PSC in October 2009.

<u>Cash Flows from Investing Activities</u>. Net cash used in investing activities was $129.6 million in 2009, $177.4 million in 2008 and $148.2 million in 2007. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures were $129 million in 2009, a 29% decrease from the $181 million in 2008, primarily due to lower system infrastructure investments consistent with slower customer growth.

We have a substantial capital expansion program for construction of distribution facilities, purchase of equipment and other general improvements. This program primarily supports our system infrastructure and the growth in our customer base. Gross utility construction expenditures totaling $195.4 million are budgeted for 2010. The $195.4 million includes $46.3 million in capital expenditures, largely deferred from 2009, for pipeline infrastructure to serve two gas-fired power generation projects in North Carolina. We are not contractually obligated to expend capital until the work is completed. Even though we are seeing a slower pace of core residential and commercial customer growth in our service territory due to the downturn in the housing market and other economic factors, significant utility construction expenditures are expected to continue to meet long-term growth and are part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years.

We have deferred the development and construction of our previously announced LNG peak storage facility in Robeson County, North Carolina based on our current growth projections, which indicate that we may need to resume development of the project in 2011 to prepare for construction in 2012 in order to provide service in 2015. This LNG peak storage facility, with an intended capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand, is part of our plan to provide safe, reliable gas distribution service to our growing customer base and manage our seasonal demand. We intend to design, construct, own and operate this facility as a regulated utility project. Preliminary estimates place the cost of the facility in the \$300 million to \$350 million range, with \$5.2 million incurred in fiscal year 2009. With the uncertain economic outlook, we will monitor customer growth trends in our markets and plan for the development of the Robeson project when needed to meet future customer requirements.

In October 2009, we reached an agreement with Progress Energy Carolinas to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. The agreement, which is subject to NCUC approval, calls for us to construct 38 miles of 20-inch transmission pipeline along with additional compression facilities to provide natural gas delivery service to the plant by July 2012. Our investment in the pipeline and compression facilities is estimated at \$85 million and is supported by a long-term service agreement. We anticipate making the capital expenditures related to the project during 2011 and 2012. To provide the additional delivery service, we have executed an agreement with Cardinal Pipeline Company, LLC (Cardinal) to expand our firm capacity requirement by 149,000 dekatherms per day to serve this facility. This will require Cardinal to spend as much as \$39.2 million to expand its system. As a 22% equity venture partner of Cardinal, we will invest as much as \$8.7 million in Cardinal's system expansion.

During 2007, \$2.2 million of supplier refunds was recorded as restricted cash. In 2008, restrictions on cash totaling \$2.2 million were removed pursuant to a 2007 NCUC order, and we liquidated all certificates of deposit and similar investments that held any supplier refunds due to customers and transferred these funds upon maturity to the North Carolina deferred account.

In 2009 and 2008, we contributed \$.9 million and \$10.9 million, respectively, to our Hardy Storage joint venture as part of our equity contribution for construction of the FERC regulated interstate storage facility.

During 2008, we sold various properties located in Burlington and High Point, North Carolina, Spartanburg, South Carolina and Nashville, Tennessee for \$13.2 million, net of expenses. In accordance with utility plant accounting, we recorded the disposition of the land from these sales as a pre-tax gain of \$1.2 million with a deferral of \$.5 million related to the Nashville sale. The net pre-tax gain of \$.7 million was recorded in "Other Income (Expense)" in the consolidated statements of income. We recorded a gain of \$3.1 million on the disposition of the buildings as a charge to "Accumulated depreciation" in the consolidated balance sheets. We entered into a sale-leaseback agreement on the Nashville property for a lease of 18 ½ months, where the $.5 million deferred gain will be amortized on a straight-line basis over the life of the lease and recorded to "Other Income (Expense)" in the consolidated statements of income. During 2009 and 2008, we recorded amortization of the deferred gain of $309,088 and $38,636, respectively.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was ($214.1) million in 2009, $107.7 million in 2008 and ($86.6) million in 2007. Funds are primarily provided from bank borrowings and the issuance of common stock through dividend reinvestment and stock purchase and employee stock purchase plans, net of purchases under the common stock repurchase program. We may sell common stock and long-term debt when market and other conditions favor such long-term financing. Funds are primarily used to pay down outstanding short-term bank borrowings, to repurchase common stock under the common stock repurchase program and to pay quarterly dividends on our common stock. As of October 31, 2009, our current assets were $513.1 million and our current liabilities were $600.2 million, primarily due to seasonal requirements as discussed above.

As of October 31, 2009, we had committed lines of credit of $450 million with the ability to expand up to $600 million under our syndicated credit facility that expires April 2011 to meet working capital needs. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $450 million. Outstanding short-term bank borrowings decreased from $406.5 million as of October 31, 2008 to $306 million as of October 31, 2009 primarily due to lower commodity gas costs and lower interest payments for short-term debt. During the twelve months ended October 31, 2009, short-term bank borrowings ranged from $131.5 million to $556.5 million, and interest rates ranged from .50% to 2.84% (weighted average of .85%).

Effective December 3, 2008, we entered into a syndicated seasonal credit facility with aggregate commitments totaling $150 million. Advances under this seasonal facility bore interest at a rate based on the 30-day LIBOR rate plus from 75 to 175 basis points, based on our credit ratings. This seasonal credit facility expired on March 31, 2009. We entered into this facility to provide lines of credit in addition to the syndicated credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements and general corporate needs. This seasonal credit facility replaced the two short-term credit facilities with banks for unsecured commitments totaling $75 million that were effective from October 27 and 29, 2008 through December 3, 2008.

As of October 31, 2009, we had available letters of credit of $5 million under our syndicated credit facility, of which $2.4 million were issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general liability policies. As of October 31, 2009, unused lines of credit available under our syndicated credit facility, including the issuance of the letters of credit, totaled $141.6 million.

The level of short-term bank borrowings can vary significantly due to changes in the wholesale prices of natural gas, the level of purchases of natural gas supplies for storage and hedging transactions to serve customer demand. We pay our suppliers for natural gas purchases before we collect our costs from customers through their monthly bills. If wholesale gas prices increase, we may incur more short-term debt for natural gas inventory and other operating costs since collections from customers could be slower and some customers may not be able to pay their gas bills on a timely basis.

At this time, we do not anticipate issuing long-term debt in fiscal 2010, but intend to issue up to $125 million in long-term debt in fiscal 2011 for general operating purposes. The timing of this issuance has not yet been determined. We will continue to monitor customer growth trends in our markets along with the economic recovery of our service area for the timing of any infrastructure investments that would require the need for additional long-term debt.

In September 2009, the balance of $30 million of our 7.35% medium-term notes became due and was retired. The balance of $60 million of our 7.8% medium-term notes becomes due in September 2010.

We had a shelf registration statement filed with the SEC that expired on December 1, 2008 that could have been used for the issuance of either debt or equity. The remaining balance of unused long-term financing available under this shelf registration statement as of October 31, 2008 was $109.4 million.

From time to time, we have repurchased shares of common stock under our Common Stock Open Market Purchase Program and our ASR program as described in Note 5 to the consolidated financial statements. On March 6, 2009, the Board of Directors authorized the consolidation of these programs and the repurchase of up to an additional four million shares. Upon this authorization, 7,010,074 shares were available for repurchase. Upon repurchase, such shares will be cancelled and become authorized shares available for issuance.

On March 20, 2009, through an ASR agreement with an investment bank, we repurchased and retired 700,000 shares of common stock for $18.4 million, leaving a balance of 6,310,074 shares in the Common Stock Open Market Purchase Program. On April 21, 2009, final settlement of the transaction occurred, and we received cash of $.6 million from the investment bank. During 2008 and 2007, 1.6 million shares and 2 million shares were repurchased for $42.7 million and $54.2 million, respectively. We anticipate repurchasing 1.8 million shares of common stock through an ASR agreement in our fiscal year 2010.

During 2009, we issued $14.4 million of common stock through dividend reinvestment and stock purchase and employee stock purchase plans. As a result of an administrative error, we received $13.2 million from December 1, 2008 through October 31, 2009 from the sale of shares of common stock under our dividend reinvestment and stock purchase plan that were from unregistered shares. To ensure compliance with the Securities Act of 1933, as amended, to provide a remedy to any participant aggrieved by the failure to register and to notify participants of their rights as generally prescribed by the applicable securities laws, we intend to file a registration statement on Form S-3 to register a rescission offer to dividend reinvestment and stock purchase plan participants for the unregistered shares and to register the unregistered shares. For further information, see Note 5 to the consolidated financial statements.

We have paid quarterly dividends on our common stock since 1956. We increased our common stock dividend on an annualized basis by $.04 per share in 2009, 2008 and 2007. Dividends of $78.4 million, $75.5 million and $73.6 million for 2009, 2008 and 2007, respectively, were paid on common stock. Provisions contained in certain note agreements under which long-term debt was issued restrict the amount of cash dividends that may be paid. As of October 31, 2009, our retained earnings were not restricted. On December 17, 2009, the Board of Directors declared a quarterly dividend on common stock of $.27 per share, payable January 15, 2010 to shareholders of record at the close of business on December 28, 2009. For further information, see Note 3 to the consolidated financial statements.

Our long-term targeted capitalization ratio is 45-50% in long-term debt and 50-55% in common equity. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. As of October 31, 2009, our capitalization, including current maturities of long-term debt, consisted of 46% in long-term debt and 54% in common equity.

The components of our total debt outstanding (short-term and long-term) to our total capitalization as of October 31, 2009 and 2008 are summarized in the table below.

| | October 31 | | October 31 | |
|---|---|---|---|---|
| In thousands | 2009 | Percentage | 2008 | Percentage |
| Short-term debt | $ 306,000 | 15% | $ 406,500 | 19% |
| Current portion of long-term debt | 60,000 | 3% | 30,000 | 1% |
| Long-term debt | 732,512 | 36% | 794,261 | 38% |
| Total debt | 1,098,512 | 54% | 1,230,761 | 58% |
| Common stockholders' equity | 927,948 | 46% | 887,244 | 42% |
| Total capitalization (including short-term debt) | $ 2,026,460 | 100% | $ 2,118,005 | 100% |

Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. In determining our credit ratings, the rating agencies consider various factors. The more significant quantitative factors include:

- Ratio of total debt to total capitalization, including balance sheet leverage,
- Ratio of net cash flows to capital expenditures,
- Funds from operations interest coverage,
- Ratio of funds from operations to average total debt,
- Pension liabilities and funding status, and
- Pre-tax interest coverage.

Qualitative factors include, among other things:

- Stability of regulation in the jurisdictions in which we operate,
- Consistency of our earnings over time,
- Risks and controls inherent in the distribution of natural gas,
- Predictability of cash flows,
- Quality of business strategy and management,
- Corporate governance guidelines and practices,
- Industry position, and
- Contingencies.

As of October 31, 2009, all of our long-term debt was unsecured. Our long-term debt is rated "A" by Standard & Poor's Ratings Services and "A3" by Moody's Investors Service (Moody's). Currently, with respect to our long-term debt, the credit agencies maintain their stable outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a rating agency if, in its judgment, circumstances warrant a change.

We are subject to default provisions related to our long-term debt and short-term borrowings. Failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. There are cross-default provisions in all of our debt agreements. As of October 31, 2009, there has been no event of default giving rise to acceleration of our debt.

The default provisions of our senior notes include:

- Failure to make principal, interest or sinking fund payments,
- Interest coverage of 1.75 times,
- Total debt cannot exceed 70% of total capitalization,
- Funded debt of all subsidiaries in the aggregate cannot exceed 15% of total company capitalization,
- Failure to make payments on any capitalized lease obligation,
- Bankruptcy, liquidation or insolvency, and
- Final judgment against us in excess of $1 million that after 60 days is not discharged, satisfied or stayed pending appeal.

The default provisions of our medium-term notes are:

- Failure to make principal, interest or sinking fund payments,
- Failure after the receipt of a 90-day notice to observe or perform for any covenant or agreement in the notes or in the indenture under which the notes were issued, and
- Bankruptcy, liquidation or insolvency.

Contractual Obligations and Commitments

We have incurred various contractual obligations and commitments in the normal course of business. As of October 31, 2009, our estimated recorded and unrecorded contractual obligations are as follows.

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| In thousands | Less than 1 year | 1-3 Years | 4-5 Years | After 5 Years | Total |
| Recorded contractual obligations: | | | | | |
| Long-term debt (1) | $ 60,000 | $ 60,000 | $ 100,000 | $ 572,512 | $ 792,512 |
| Short-term debt (2) | 306,000 | - | - | - | 306,000 |
| Uncertain income tax obligations (3) | 293 | - | - | - | 293 |
| Total | $ 366,293 | $ 60,000 | $ 100,000 | $ 572,512 | $ 1,098,805 |

(1) See Note 3 to the consolidated financial statements.
(2) See Note 4 to the consolidated financial statements.
(3) See Note 10 to the consolidated financial statements.

| In thousands | Less than 1 year | 1-3 Years | 4-5 Years | After 5 Years | Total |
|---|---|---|---|---|---|
| Unrecorded contractual obligations and commitments: (1) | | | | | |
| Pipeline and storage capacity (2) | $ 151,370 | $ 392,726 | $ 134,333 | $ 261,694 | $ 940,123 |
| Gas supply (3) | 14,929 | 191 | - | - | 15,120 |
| Interest on long-term debt (4) | 54,443 | 139,560 | 81,699 | 573,068 | 848,770 |
| Telecommunications and information technology (5) | 15,660 | 7,366 | - | - | 23,026 |
| Qualified and nonqualified pension plan funding (6) | 22,704 | 34,721 | 11,438 | - | 68,863 |
| Postretirement benefits plan funding (6) | 2,700 | 4,800 | 1,500 | - | 9,000 |
| Operating leases (7) | 5,008 | 12,515 | 7,886 | 1,984 | 27,393 |
| Other purchase obligations (8) | 8,084 | - | - | - | 8,084 |
| Letters of credit (9) | 2,714 | 8,142 | 5,428 | - | 16,284 |
| Total | $ 277,612 | $ 600,021 | $ 242,284 | $ 836,746 | $ 1,956,663 |

(1) In accordance with generally accepted accounting principles (GAAP), these items are not reflected in our consolidated balance sheets.
(2) Recoverable through PGA procedures.
(3) Reservation fees are recoverable through PGA procedures.
(4) See Note 3 to the consolidated financial statements.
(5) Consists primarily of maintenance fees for hardware and software applications, usage fees, local and long-distance data costs, frame relay, and cell phone and pager usage fees.
(6) Estimated funding beyond five years is not available. See Note 8 to the consolidated financial statements.
(7) See Note 7 to the consolidated financial statements.
(8) Consists primarily of pipeline products, vehicles, contractors and merchandise.
(9) See Note 4 to the consolidated financial statements.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases, letters of credit and the credit extended by our counterparty in over-the-counter (OTC) derivative contracts. The letters of credit and operating leases are discussed in Note 4 and Note 7, respectively, to the consolidated financial statements and are reflected in the table above. The credit extended by our counterparty in OTC derivative contracts is discussed in Note 6 to the consolidated financial statements.

Piedmont Energy Partners, Inc., a wholly owned subsidiary of Piedmont, has entered into a guaranty in the normal course of business. The guaranty involves some levels of performance and credit risk that are not included on our consolidated balance sheets. We have recorded an estimated liability of $1.2 million as of October 31, 2009 and 2008. The possibility of having to perform on the guaranty is largely dependent upon the future operations of Hardy Storage, third parties or the occurrence of certain future events. For further information on this guaranty, see Note 11 to the consolidated financial statements.

Critical Accounting Estimates

We prepare the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results may differ significantly from these estimates and assumptions. We base our estimates on historical experience, where applicable, and other relevant factors that we believe are reasonable under the circumstances. On an ongoing basis, we evaluate estimates and assumptions and make adjustments in subsequent periods to reflect more current information if we determine that modifications in assumptions and estimates are warranted.

Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or a different estimate that could have been used would have had a material impact on our financial condition or results of operations. We consider regulatory accounting, revenue recognition, and pension and postretirement benefits to be our critical accounting estimates. Management is responsible for the selection of these critical accounting estimates. Management has discussed these critical accounting estimates presented below with the Audit Committee of the Board of Directors.

Regulatory Accounting. Our regulated utility segment is subject to regulation by certain state and federal authorities. Our accounting policies conform to the accounting regulations required by rate regulated operations and are in accordance with accounting requirements and ratemaking practices prescribed by the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. We then recognize these deferred regulatory assets and liabilities through the income statement in the period in which the same amounts are reflected in rates. If we, for any reason, cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, we would eliminate from the balance sheet the regulatory assets and liabilities related to those portions ceasing to meet such criteria and include them in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such an event could have a material effect on our results of operations in the period this action was recorded. Regulatory assets as of October 31, 2009 and 2008, totaled $337.5 million and $263.2 million, respectively. Regulatory liabilities as of October 31, 2009 and 2008, totaled $409.3 million and $383.7 million, respectively. The detail of these regulatory assets and liabilities is presented in Note 1.B to the consolidated financial statements.

Revenue Recognition. Utility sales and transportation revenues are based on rates approved by state regulatory commissions. Base rates charged to customers may not be changed without formal approval by the regulatory commission in that jurisdiction; however, the wholesale cost of gas component of rates may be adjusted periodically under PGA procedures. In South Carolina and Tennessee, we have WNA mechanisms that are designed to protect a portion of our revenues against warmer-than-normal weather as deviations from normal weather can affect our financial performance and liquidity. The WNA also serves to offset the impact of colder-than-normal weather by reducing the amounts we can charge our customers. In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The margin earned monthly under the margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection or recover any under-collection. The gas cost portion of our costs is recoverable through PGA procedures and is not affected by the WNA or the margin decoupling mechanism. Without the WNA or margin decoupling mechanism, our operating revenues in 2009, 2008 and 2007 would have been lower by $4.8 million, $32.2 million and $39.1 million, respectively

Revenues are recognized monthly on the accrual basis, which includes estimated amounts for gas delivered to customers but not yet billed under the cycle-billing method from the last meter reading date to month end. Meters are read throughout the month based on an approximate 30-day usage cycle; therefore, at any point in time, volumes are delivered to customers that have not been metered and billed. The unbilled revenue estimate reflects factors requiring judgment related to estimated usage by customer class, changes in weather during the period and the impact of the WNA or margin decoupling mechanism, as applicable. Secondary market revenues are recognized when the physical sales are delivered based on contract or market prices.

Pension and Postretirement Benefits. For eligible employees hired on or before December 31, 2007 (December 31, 2008 for employees covered under the bargaining unit contract in Nashville, Tennessee), we have a traditional defined benefit pension plan, which was amended to close the plan to employees hired after December 31, 2007 (December 31, 2008 for employees covered under the bargaining unit contract in Nashville, Tennessee) and to modify how benefits are accrued. We also provide certain postretirement health care and life insurance benefits to eligible employees. For further information and our reported costs of providing these benefits, see Note 8 to the consolidated financial statements. The costs of providing these benefits are impacted by numerous factors, including the provisions of the plans, changing employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions used, our estimate of these costs is a critical accounting estimate.

Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expenses and liabilities related to the plans. These factors include assumptions about the discount rate used in determining future benefit obligations, projected health care cost trend rates, expected long-term return on plan assets and rate of future compensation increases, within certain guidelines. In addition, we also use subjective factors such as withdrawal and mortality rates to estimate projected benefit obligations. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

The discount rate has been separately determined for each plan by projecting the plan's cash flows and developing a zero-coupon spot rate yield curve using non-arbitrage pricing and Moody's AA or better-rated non-callable bonds. Based on this approach, the weighted average discount rate used in the measurement of the benefit obligation for the qualified pension plan changed from 8.15% in 2008 to 5.99% in 2009. For the nonqualified pension plans, the weighted average discount rate used in the measurement of the benefit obligation changed from 8.46% in 2008 to 5.28% in 2009. Similarly, based on this approach, the weighted average discount rate for postretirement benefits changed from 8.5% in 2008 to 5.58% in 2009. Based on our review of actual cost trend rates and projected future trends in establishing health care cost trend rates, we changed the initial health care cost trend rate assumed for next year from 8.25% in 2008 to 8% in 2009, declining gradually to 5% in 2027.

In determining our expected long-term rate of return on plan assets, we review past long-term performance, asset allocations and long-term inflation assumptions. We target our asset allocations for qualified pension plan assets and other postretirement benefit assets to be approximately 50% equity securities and 50% fixed income securities. The expected long-term rate of return on plan assets was 8.5% in 2007 and 8% in 2008 and 2009. Based on a fairly stagnant inflation trend, our age-related assumed rate of increase in future compensation levels was 3.99% in 2007, decreasing to 3.97% in 2008 and decreasing to 3.92% in 2009 due to changes in the demographics of the participants.

The following reflects the sensitivity of pension cost to changes in certain actuarial assumptions for our qualified pension plan, assuming that the other components of the calculation are constant.

| Actuarial Assumption | Change in Assumption | Impact on 2009 Benefit Cost | Impact on Projected Benefit Obligation |
|---|---|---|---|
| | | Increase (Decrease) In thousands | |
| Discount rate | (.25)% | $ 62 | $ 4,783 |
| Rate of return on plan assets | (.25)% | 523 | N/A |
| Rate of increase in compensation | .25 % | 235 | 2,495 |

The following reflects the sensitivity of postretirement benefit cost to changes in certain actuarial assumptions, assuming that the other components of the calculation are constant.

| Actuarial Assumption | Change in Assumption | Impact on 2009 Postretirement Benefit Cost | Impact on Accumulated Postretirement Benefit Obligation |
|---|---|---|---|
| | | Increase (Decrease) In thousands | |
| Discount rate | (.25)% | $ 5 | $ 798 |
| Rate of return on plan assets | (.25)% | 37 | N/A |
| Health care cost trend rate | .25 % | 16 | 244 |

We utilize a number of accounting methods allowed under GAAP that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of the plan assets. If necessary, the excess is amortized over the average remaining service period of active employees.

Gas Supply and Regulatory Proceedings

In recent years, we have sought to diversify our supply portfolio through pipeline capacity arrangements that access new sources of supply and market-area storage and that diversify supply concentration away from the Gulf Coast region. We have firm, long-term transportation contract service that provides access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. We have firm, long-term market-area storage service in West Virginia from Hardy Storage, a venture in which we have a 50% equity interest in the project which is more fully discussed in Note 11 to the consolidated financial statements.

We have deferred the development and construction of our previously announced LNG peak storage facility in Robeson County, North Carolina based on revised growth projections and the economic downturn. Based on our current growth projections, we may resume development of the project in 2011 to prepare for construction in 2012 in order to provide service in 2015. With the uncertain economic outlook, we will monitor customer growth trends in our markets and plan for the development of the project when needed to meet future customer requirements.

In October 2009, we reached an agreement with Progress Energy Carolinas to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. The agreement, which is subject to NCUC approval, calls for us to construct 38 miles of 20-inch transmission pipeline along with additional compression facilities to provide natural gas delivery service to the plant by July 2012. Our investment in the pipeline and compression facilities is estimated at $85 million and is supported by a long-term service agreement. We anticipate making the capital expenditures related to the project during 2011 and 2012. To provide the additional delivery service, we have executed an agreement with Cardinal pipeline to expand our firm capacity requirement by 149,000 dekatherms per day to serve this facility. This will require Cardinal to spend as much as $39.2 million to expand its system. As a 22% equity venture partner of Cardinal, we will invest as much as $8.7 million in Cardinal's system expansion. For further information on our equity venture, see Note 11 to the consolidated financial statements. This project will increase our natural gas infrastructure in the eastern part of North Carolina and will enhance future opportunities for economic growth and development.

Secondary market transactions permit us to market gas supplies and transportation services by contract with wholesale or off-system customers. These sales contribute smaller per-unit margins to earnings; however, the program allows us to act as a wholesale marketer of natural gas and transportation capacity in order to generate operating margin from sources not restricted by the capacity of our retail distribution system. A sharing mechanism is in effect where 75% of any margin is passed through to customers in all of our jurisdictions. However, secondary market transactions in Tennessee are included in the TIP discussed in Note 2 to the consolidated financial statements.

We entered into a stipulation and agreement with FERC's Office of Enforcement regarding certain instances of alleged non-compliance with FERC's capacity release regulations regarding posting and bidding requirements for short-term releases. The agreement was approved by the FERC and required us, among other matters, to pay a civil penalty in settlement of the matter. The penalty, which was paid in July 2009, did not have a material effect on our financial position, cash flows or results of operations.

In October 2008, the NCUC approved a settlement in our general rate case proceeding that provided an annual revenue increase of $15.7 million and the continuation of the margin decoupling mechanism. The new rates became effective November 1, 2008. Also in October 2008, the PSCSC issued an order approving a settlement that provided for an annual decrease of $1.5 million in margin under the RSA mechanism based on a return on equity of 11.2%, effective November 1, 2008. In October 2009, the PSCSC issued an order approving a settlement that provides for an annual increase in margin of $1.1 million based on a return on equity of 11.2%, effective November 1, 2009.

In October 2009, we filed a petition with the PSCSC requesting approval to offer three energy efficiency programs to residential and commercial customers that are designed to promote energy conservation and efficiency. These programs are similar to approved energy efficiency programs in North Carolina. For further information on these programs, see the discussion in Note 2 to the consolidated financial statements.

In July 2009, we filed a petition with the TRA requesting approval to decouple residential rates in Tennessee and to offer three energy efficiency programs to residential customers. We are proposing a margin decoupling tracker mechanism that is designed to allow us to recover from our residential customers the approved per customer margin as approved in our last general rate proceeding. The proposed energy efficiency programs in Tennessee are designed to promote energy conservation and efficiency by residential customers and are similar to approved energy efficiency programs in North Carolina. A hearing on our requests was held on December 17–18, 2009. We are unable to predict the outcome of this proceeding at this time.

We continue to work with our regulatory commissions to earn a fair rate of return for our shareholders and provide safe, reliable natural gas distribution service to our customers. For further information about regulatory proceedings and other regulatory information, see Note 2 to the consolidated financial statements.

Equity Method Investments

For information about our equity method investments, see Note 11 to the consolidated financial statements.

Environmental Matters

We have developed an environmental self-assessment plan to assess our facilities and program areas for compliance with federal, state and local environmental regulations and to correct any deficiencies identified. As a member of the North Carolina MGP Initiative Group, we, along with other responsible parties, work directly with the North Carolina Department of Environment and Natural Resources to set priorities for manufactured gas plant (MGP) site remediation. For additional information on environmental matters, see Note 7 to the consolidated financial statements.

Accounting Guidance

We adopted the Financial Accounting Standards Board (FASB) guidance related to the FASB Accounting Standards Codification (ASC) and the Hierarchy of Generally Accepted Accounting Principles (GAAP). This statement identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are prepared in conformity with GAAP in the United States of America. This statement replaces prior guidance related to the hierarchy of GAAP and establishes the FASB ASC as the source of authoritative accounting principles by the FASB. Rules and interpretative releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for all SEC registrants. The adoption of this guidance did not have any impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued guidance related to fair value measurements and disclosures. In November 2007, the FASB delayed the implementation of the fair value guidance for one year only for other nonfinancial assets and liabilities. This guidance provided enhanced direction for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) the measurement of assets or liabilities at fair value, but does not expand the use of fair value measurement to any new circumstances. We adopted the fair value guidance on November 1, 2008 for our financial assets and liabilities, which consist primarily of derivatives that we record on the consolidated balance sheets in accordance with derivative accounting standards. We adopted the additional fair value guidance on November 1, 2009 for our nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis, such as the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets and long-lived assets impairment tests. The adoption of the fair value guidance for our financial assets and liabilities had no impact on our financial position, results of operations or cash flows. For additional information regarding fair value measurements, see Note 6 to the consolidated financial statements.

In February 2007, the FASB issued guidance related to the fair value measurement of financial instruments that provides companies with an option to report selected financial assets and liabilities at fair value. Its objective is to reduce the complexity in accounting for financial instruments and to mitigate the volatility in earnings caused by measuring related assets and liabilities differently. Although the guidance related to the fair value measurement of financial instruments does not eliminate disclosure requirements included in other accounting standards, it does establish additional presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. This guidance is effective for financial statements issued for fiscal years beginning after November 15, 2007, with early adoption permitted for an entity that has elected also to apply the fair value guidance early. Accordingly, we adopted guidance related to the fair value measurement of selected financial assets and liabilities for our fiscal year beginning November 1, 2008 and did not elect the option to measure any applicable financial assets or liabilities at fair value pursuant to those provisions.

In April 2007, the FASB issued guidance related to "Offsetting of Amounts Related to Certain Contracts," to replace the terms conditional contracts and exchange contracts with the term derivative instruments. The new guidance permits a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance is effective for fiscal years beginning after November 15, 2007, with early application permitted. Accordingly, we have evaluated the impacts of the right to offset fair value amounts pursuant to the new guidance for our fiscal year beginning November 1, 2008. Our policy has been to present our positions, exclusive of any receivable or payable, with the same counterparty on a net basis; however, we elected "not to net" under the new guidance and have reflected reclassifications on our statement of financial position.

In December 2007, the FASB issued new accounting guidance related to business combinations which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date at fair value. This guidance changes the accounting for business combinations in various areas, including contingency consideration, preacquistion contingencies, transaction costs and restructuring costs. In addition, changes in the acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. We will apply the provisions of this guidance to any acquisitions we may complete after November 1, 2009.

In March 2008, the FASB issued guidance related to disclosures about derivative instruments and hedging activities by requiring expanded qualitative, quantitative and credit-risk disclosures about derivative instruments and hedging activities, but without changing the scope or accounting under derivatives and hedging and the related accounting interpretations. The guidance requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. The guidance also amended the disclosure requirements to clarify that derivative instruments are subject to concentration-of-credit-risk disclosures. The guidance is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early adoption permitted. We adopted the new guidance on February 1, 2009. Since only additional disclosures concerning derivatives and hedging activities were required, there was no impact on our financial position, results of operations, or cash flows.

In December 2008, the FASB issued new accounting guidance for employers' disclosures about plan assets of defined benefit pension and other postretirement plans. This guidance requires that employers provide more transparency about the assets held by retirement plans or other postretirement employee benefit plans, the concentration of risk in those plans and information about the fair value measurements of plan assets similar to the disclosures required by the fair value guidance. The guidance is effective for fiscal years ending after December 15, 2009, with earlier application permitted. Since only additional disclosures about plan assets of defined benefit pension and other postretirement plans are required, it is not expected to have a material impact on our financial position, results of operations or cash flows. We will adopt the guidance on benefit plan assets during our fiscal year ending October 31, 2010.

In April 2009, the FASB issued additional guidance related to interim disclosures about fair values of financial instruments that requires publicly traded companies to disclose the fair value of financial instruments during interim reporting in addition to the information provided annually. The guidance was effective for periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the guidance for our quarter ended April 30, 2009. The adoption had no impact on our consolidated financial statements. Comparative information is not required at initial adoption. The disclosure requirements are presented in "Fair Value Measurements" in Note 6 to the consolidated financial statements.

Also in April 2009, the FASB issued guidance for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying transactions that are not orderly. We adopted the guidance effective for our quarter ended April 30, 2009, as concurrent adoption is required with the early adoption of the interim reporting fair value disclosure guidance. The adoption had no impact on our consolidated financial statements.

In May 2009, the FASB issued new guidance related to management's review of subsequent events. The guidance is effective for interim and annual periods ending after June 15, 2009. We adopted the guidance for the period ended July 31, 2009. This guidance establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before the date that the financial statements are issued or are available to be issued. It requires disclosure of the date through which an entity has evaluated subsequent events. Such disclosure is included in Note 15 to the consolidated financial statements. It had no impact on our financial position, results of operations or cash flows as the result of our evaluation.

## Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to various forms of market risk, including the credit risk of our suppliers and our customers, interest rate risk, commodity price risk and weather risk. We seek to identify, assess, monitor and manage market risk and credit risk in accordance with defined policies and procedures under an Enterprise Risk Management Policy and with the direction of the Energy Price Risk Management Committee. Risk management is guided by senior management with Board of Directors' oversight, and senior management takes an active role in the development of policies and procedures.

We hold all financial instruments discussed below for purposes other than trading.

Credit Risk

We enter into contracts with third parties to buy and sell natural gas. Our policy requires counterparties to have an investment-grade credit rating at the time of the contract. The policy specifies limits on the contract amount and duration based on the counterparty's credit rating. The policy is also designed to mitigate credit risks through a requirement for credit enhancements that include letters of credit or parent guaranties. In order to minimize our exposure, we continually re-evaluate third-party creditworthiness and market conditions and modify our requirements accordingly.

We also enter into contracts with third parties to manage some of our supply and capacity assets for the purpose of maximizing their value. These arrangements include a counterparty credit evaluation according to our policy described above prior to contract execution and typically have durations of one year or less. In the event that a party is unable to perform under these arrangements, we have exposure to satisfy our underlying supply or demand contractual obligations that were incurred while under the management of this third party.

We have mitigated exposure to the risk of non-payment of utility bills by customers. In North Carolina and South Carolina, gas costs related to uncollectible accounts are recovered through PGA procedures. In Tennessee, the gas cost portion of net write-offs for a fiscal year that exceed the gas cost portion included in base rates is recovered through PGA procedures. To manage the non-gas cost customer credit risk, we evaluate credit quality and payment history and may require cash deposits from those customers that do not satisfy our predetermined credit standards. Significant increases in the price of natural gas can also slow our collection efforts as customers experience increased difficulty in paying their gas bills, leading to higher than normal accounts receivable.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on short-term debt. As of October 31, 2009, all of our long-term debt was issued at fixed rates, and therefore not subject to interest rate risk.

We have short-term borrowing arrangements to provide working capital and general corporate liquidity. The level of borrowings under such arrangements varies from period to period depending upon many factors, including the cost of wholesale natural gas and our gas supply hedging programs, our investments in capital projects, the level and expense of our storage inventory and the collection of receivables. Future short-term interest expense and payments will be impacted by both short-term interest rates and borrowing levels.

As of October 31, 2009, we had $306 million of short-term debt outstanding under our syndicated credit facility at an interest rate of .5%. The carrying amount of our short-term debt approximates fair value. A change of 100 basis points in the underlying average interest rate for our short-term debt would have caused a change in interest expense of approximately $3 million during 2009.

As of October 31, 2009, information about our long-term debt is presented below.

| In millions | 2010 | 2011 | 2012 | 2013 | 2014 | Thereafter | Total | Fair Value as of October 31, 2009 |
|---|---|---|---|---|---|---|---|---|
| | Expected Maturity Date | | | | | | | |
| Fixed Rate Long-term Debt | $ 60 | $ 60 | $ - | $ - | $ 100 | $ 572.5 | $ 792.5 | $ 910.3 |
| Average Interest Rate | 7.80 % | 6.55 % | - % | - % | 5.00 % | 6.92 % | 6.72 % | |

Commodity Price Risk

We have mitigated the cash flow risk resulting from commodity purchase contracts under our regulatory gas cost recovery mechanisms that permit the recovery of these costs in a timely manner. As such, we face regulatory recovery risk associated with these costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas, including costs associated with our hedging programs under the recovery mechanism allowed by each of our state regulators. Under our PGA procedures, differences between gas costs incurred and gas costs billed to customers are deferred and any under-recoveries are included in "Amounts due from customers" or any over-recoveries are included in "Amounts due to customers" in our consolidated balance sheets for collection or refund over subsequent periods. When we have "Amounts due from customers," we earn a carrying charge that mitigates any incremental short-term borrowing costs. When we have "Amounts due to customers," we incur a carrying charge that we must refund to our customers.

We manage our gas supply costs through a portfolio of short- and long-term procurement and storage contracts with various suppliers. We actively manage our supply portfolio to balance sales and delivery obligations. We inject natural gas into storage during the summer months and withdraw the gas during the winter heating season. In the normal course of business, we utilize New York Mercantile Exchange (NYMEX) exchange traded instruments and over-the-counter instruments of various durations for the forward purchase of a portion of our natural gas requirements, subject to regulatory review and approval.

Our gas purchasing practices are subject to regulatory reviews in all three states in which we operate. Costs have never been disallowed on the basis of prudence in any jurisdiction.

Weather Risk

We are exposed to weather risk in our regulated utility segment in South Carolina and Tennessee where revenues are collected from volumetric rates without a margin decoupling mechanism. Our rates are designed based on an assumption of normal weather. In these states, this risk is mitigated by WNA mechanisms that are designed to offset the impact of colder-than-normal or warmer-than-normal weather in our residential and commercial markets. In North Carolina, we manage our weather risk through a margin decoupling mechanism that allows us to recover our approved margin from residential and commercial customers independent of volumes sold.

Additional information concerning market risk is set forth in "Financial Condition and Liquidity" in Item 7 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 8. Financial Statements and Supplementary Data

Consolidated financial statements required by this item are listed in Item 15 (a) 1 in Part IV of this Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Piedmont Natural Gas Company, Inc.

We have audited the accompanying consolidated balance sheets of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2009 and 2008, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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, such consolidated financial statements present fairly, in all material respects, the financial position of Piedmont Natural Gas Company, Inc. and subsidiaries at October 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of October 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated December 23, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 23, 2009

Consolidated Balance Sheets
October 31, 2009 and 2008

ASSETS

| In thousands | 2009 | 2008 |
|---|---|---|
| Utility Plant: | | |
| Utility plant in service | $ 3,071,742 | $ 2,997,186 |
| Less accumulated depreciation | 862,079 | 813,822 |
| Utility plant in service, net | 2,209,663 | 2,183,364 |
| Construction work in progress | 87,978 | 57,470 |
| Plant held for future use | 6,751 | - |
| Total utility plant, net | 2,304,392 | 2,240,834 |
| Other Physical Property, at cost (net of accumulated depreciation of $2,497 in 2009 and $2,351 in 2008) | 719 | 864 |
| Current Assets: | | |
| Cash and cash equivalents | 7,558 | 6,991 |
| Trade accounts receivable (less allowance for doubtful accounts of $990 in 2009 and $1,066 in 2008) | 70,979 | 82,346 |
| Income taxes receivable | 44,413 | 731 |
| Other receivables | 4,712 | 393 |
| Unbilled utility revenues | 33,925 | 51,819 |
| Inventories: | | |
| Gas in storage | 103,584 | 190,275 |
| Materials, supplies and merchandise | 5,262 | 6,524 |
| Gas purchase options, at fair value | 2,559 | 22,645 |
| Amounts due from customers | 196,130 | 181,745 |
| Prepayments | 43,930 | 79,831 |
| Other | 96 | 96 |
| Total current assets | 513,148 | 623,396 |
| Noncurrent Assets: | | |
| Equity method investments in non-utility activities | 104,430 | 99,214 |
| Goodwill | 48,852 | 48,852 |
| Marketable securities, at fair value | 441 | - |
| Overfunded postretirement asset | - | 6,797 |
| Regulatory asset for postretirement benefits | 76,905 | 28,732 |
| Gas purchase options, at fair value | - | 32,434 |
| Unamortized debt expense | 9,177 | 9,915 |
| Regulatory cost of removal asset | 16,293 | 6,398 |
| Other | 44,462 | 40,965 |
| Total noncurrent assets | 300,560 | 273,307 |
| Total | $ 3,118,819 | $ 3,138,401 |

See notes to consolidated financial statements.

Consolidated Balance Sheets
October 31, 2009 and 2008

CAPITALIZATION AND LIABILITIES

| In thousands | 2009 | 2008 |
|---|---|---|
| Capitalization: | | |
| Stockholders' equity: | | |
| Cumulative preferred stock - no par value - 175 shares authorized | $ - | $ - |
| Common stock - no par value - shares authorized: 200,000; shares outstanding: 73,266 in 2009 and 73,246 in 2008 | 471,569 | 471,565 |
| Paid-in capital | - | 763 |
| Retained earnings | 458,826 | 414,246 |
| Accumulated other comprehensive income (loss) | (2,447) | 670 |
| Total stockholders' equity | 927,948 | 887,244 |
| Long-term debt | 732,512 | 794,261 |
| Total capitalization | 1,660,460 | 1,681,505 |
| Current Liabilities: | | |
| Current maturities of long-term debt | 60,000 | 30,000 |
| Notes payable | 306,000 | 406,500 |
| Trade accounts payable | 67,010 | 91,142 |
| Other accounts payable | 48,431 | 45,148 |
| Income taxes accrued | - | 4,414 |
| Accrued interest | 21,294 | 22,777 |
| Customers' deposits | 25,202 | 23,881 |
| Deferred income taxes | 14,138 | 6,878 |
| General taxes accrued | 19,993 | 18,932 |
| Gas purchase options, at fair value | 30,603 | 42,205 |
| Other | 7,540 | 12,300 |
| Total current liabilities | 600,211 | 704,177 |
| Noncurrent Liabilities: | | |
| Deferred income taxes | 377,562 | 305,362 |
| Unamortized federal investment tax credits | 2,422 | 2,626 |
| Regulatory liability for postretirement benefits | - | 372 |
| Accumulated provision for postretirement benefits | 31,641 | 16,257 |
| Cost of removal obligations | 408,955 | 367,450 |
| Gas purchase options, at fair value | - | 22,177 |
| Other | 37,568 | 38,475 |
| Total noncurrent liabilities | 858,148 | 752,719 |
| Commitments and Contingencies (Note 7) | | |
| Total | $ 3,118,819 | $ 3,138,401 |

See notes to consolidated financial statements.

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Consolidated Statements of Income
For the Years Ended October 31, 2009, 2008 and 2007

| In thousands except per share amounts | 2009 | 2008 | 2007 |
|---|---|---|---|
| Operating Revenues | $ 1,638,116 | $ 2,089,108 | $ 1,711,292 |
| Cost of Gas | 1,076,542 | 1,536,135 | 1,187,127 |
| Margin | 561,574 | 552,973 | 524,165 |
| Operating Expenses: | | | |
| Operations and maintenance | 208,105 | 210,757 | 214,442 |
| Depreciation | 97,425 | 93,121 | 88,654 |
| General taxes | 34,590 | 33,170 | 32,407 |
| Income taxes | 70,079 | 62,814 | 51,315 |
| Total operating expenses | 410,199 | 399,862 | 386,818 |
| Operating Income | 151,375 | 153,111 | 137,347 |
| Other Income (Expense): | | | |
| Income from equity method investments | 33,464 | 27,718 | 37,156 |
| Non-operating income | 32 | 1,320 | 2,218 |
| Charitable contributions | (2,011) | (1,327) | (587) |
| Non-operating expense | (1,558) | (864) | (164) |
| Income taxes | (11,803) | (10,678) | (14,311) |
| Total other income (expense) | 18,124 | 16,169 | 24,312 |
| Utility Interest Charges: | | | |
| Interest on long-term debt | 55,105 | 55,449 | 55,440 |
| Allowance for borrowed funds used during construction | (2,298) | (4,002) | (3,799) |
| Other | (6,132) | 7,826 | 5,631 |
| Total utility interest charges | 46,675 | 59,273 | 57,272 |
| Net Income | $ 122,824 | $ 110,007 | $ 104,387 |
| Average Shares of Common Stock: | | | |
| Basic | 73,171 | 73,334 | 74,250 |
| Diluted | 73,461 | 73,612 | 74,472 |
| Earnings Per Share of Common Stock: | | | |
| Basic | $ 1.68 | $ 1.50 | $ 1.41 |
| Diluted | $ 1.67 | $ 1.49 | $ 1.40 |

See notes to consolidated financial statements.

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2009, 2008 and 2007

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Cash Flows from Operating Activities: | | | |
| Net income | $ 122,824 | $ 110,007 | $ 104,387 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 102,592 | 97,637 | 93,355 |
| Amortization of investment tax credits | (204) | (358) | (434) |
| Allowance for doubtful accounts | (76) | 522 | (695) |
| Gain on sale of property | (495) | (711) | - |
| Earnings from equity method investments | (33,464) | (27,718) | (37,156) |
| Distributions of earnings from equity method investments | 23,954 | 34,060 | 27,884 |
| Deferred income taxes | 81,468 | 28,370 | 23,854 |
| Stock-based compensation expense | - | 338 | 336 |
| Changes in assets and liabilities: | | | |
| Gas purchase options, at fair value | 18,741 | 23,029 | (10,578) |
| Receivables | 25,018 | (12,685) | 14,892 |
| Inventories | 87,953 | (60,139) | 7,743 |
| Amounts due from customers | (14,385) | (105,710) | 13,599 |
| Settlement of legal asset retirement obligations | (1,480) | (1,358) | (1,660) |
| Overfunded postretirement asset | 6,797 | 29,459 | (36,256) |
| Regulatory asset for postretirement benefits | (48,173) | (26,867) | (1,786) |
| Other assets | (13,573) | (8,936) | 10,227 |
| Accounts payable | (22,154) | (8,617) | 13,069 |
| Amounts due to customers | - | (162) | 39 |
| Regulatory liability for postretirement benefits | (372) | (13,504) | 13,876 |
| Provision for postretirement benefits | 15,384 | (1,212) | 17,469 |
| Other liabilities | (6,085) | 13,757 | (18,664) |
| Total adjustments | 221,446 | (40,805) | 129,114 |
| Net cash provided by operating activities | 344,270 | 69,202 | 233,501 |
| Cash Flows from Investing Activities: | | | |
| Utility construction expenditures | (129,006) | (181,001) | (135,231) |
| Allowance for funds used during construction | (2,298) | (4,002) | (3,799) |
| Contributions to equity method investments | (862) | (10,917) | (12,914) |
| Distributions of capital from equity method investments | 32 | 98 | 344 |
| Proceeds from sale of property | 748 | 13,159 | - |
| Decrease (increase) in restricted cash | - | 2,196 | (2,211) |
| Investment in marketable securities | (380) | - | - |
| Other | 2,154 | 3,090 | 5,576 |
| Net cash used in investing activities | (129,612) | (177,377) | (148,235) |

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2009, 2008 and 2007

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Cash Flows from Financing Activities: | | | |
| Borrowings under notes payable | 1,075,000 | 1,687,000 | 1,120,500 |
| Repayments under notes payable | (1,175,500) | (1,476,000) | (1,095,000) |
| Retirement of long-term debt | (31,749) | (626) | (113) |
| Expenses related to the issuance of long-term debt | - | (10) | (5) |
| Expenses related to expansion of the short-term facility | - | (113) | - |
| Issuance of common stock through dividend reinvestment and employee stock plans | 14,435 | 15,591 | 15,782 |
| Repurchases of common stock | (17,857) | (42,678) | (54,240) |
| Dividends paid | (78,370) | (75,513) | (73,561) |
| Other | (50) | - | - |
| Net cash provided by (used in) financing activities | (214,091) | 107,651 | (86,637) |
| Net Increase (Decrease) in Cash and Cash Equivalents | 567 | (524) | (1,371) |
| Cash and Cash Equivalents at Beginning of Year | 6,991 | 7,515 | 8,886 |
| Cash and Cash Equivalents at End of Year | $ 7,558 | $ 6,991 | $ 7,515 |
| Cash Paid During the Year for: | | | |
| Interest | $ 61,050 | $ 63,769 | $ 63,703 |
| Income taxes | 50,787 | 29,281 | 27,423 |
| Noncash Investing and Financing Activities: | | | |
| Accrued construction expenditures | $ 1,305 | $ 1,340 | $ 741 |
| Guaranty | - | 101 | 485 |

See notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2009, 2008 and 2007

| In thousands except per share amounts | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| Balance, October 31, 2006 | $ 532,764 | $ 56 | $ 348,765 | $ 1,340 | $ 882,925 |
| Comprehensive Income: | | | | | |
| Net income | | | 104,387 | | 104,387 |
| Other comprehensive income: | | | | | |
| Minimum pension liability, net of tax of $18 | | | | 24 | 24 |
| Unrealized gain from hedging activities of equity method investments, net of tax of $314 | | | | 578 | 578 |
| Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($762) | | | | (1,276) | (1,276) |
| Total comprehensive income | | | | | 103,713 |
| Adjustment to initially apply new accounting rules for defined benefit pension and other postretirement plans, net of tax | | | | 54 | 54 |
| Common Stock Issued | 19,046 | | | | 19,046 |
| Common Stock Repurchased | (54,240) | | | | (54,240) |
| Share-Based Compensation Expense | | 336 | | | 336 |
| Dividends - Incentive Compensation Plan | | 10 | (10) | | - |
| Tax Benefit from Dividends Paid on ESOP Shares | | | 101 | | 101 |
| Dividends Declared ($.99 per share) | | | (73,561) | | (73,561) |
| Balance, October 31, 2007 | 497,570 | 402 | 379,682 | 720 | 878,374 |
| Comprehensive Income: | | | | | |
| Net income | | | 110,007 | | 110,007 |
| Other comprehensive income: | | | | | |
| Unrealized gain from hedging activities of equity method investments, net of tax of $891 | | | | 1,399 | 1,399 |
| Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($922) | | | | (1,449) | (1,449) |
| Total comprehensive income | | | | | 109,957 |
| Common Stock Issued | 16,673 | | | | 16,673 |
| Common Stock Repurchased | (42,678) | | | | (42,678) |
| Share-Based Compensation Expense | | 338 | | | 338 |
| Dividends - Incentive Compensation Plan | | 23 | (23) | | - |
| Tax Benefit from Dividends Paid on ESOP Shares | | | 93 | | 93 |
| Dividends Declared ($1.03 per share) | | | (75,513) | | (75,513) |
| Balance, October 31, 2008 | 471,565 | 763 | 414,246 | 670 | 887,244 |

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2009, 2008 and 2007

| In thousands except per share amounts | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| Comprehensive Income: | | | | | |
| Net income | | | 122,824 | | 122,824 |
| Other comprehensive income: | | | | | |
| Unrealized gain from hedging activities of equity method investments, net of tax of ($3,886) | | | | (6,032) | (6,032) |
| Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of $1,879 | | | | 2,915 | 2,915 |
| Total comprehensive income | | | | | 119,707 |
| Common Stock Issued | 17,861 | | | | 17,861 |
| Common Stock Repurchased | (17,857) | | | | (17,857) |
| Share-Based Compensation Expense | | (730) | | | (730) |
| Dividends - Incentive Compensation Plan | | (33) | 33 | | - |
| Tax Benefit from Dividends Paid on ESOP Shares | | | 93 | | 93 |
| Dividends Declared ($1.07 per share) | | | (78,370) | | (78,370) |
| Balance, October 31, 2009 | $ 471,569 | $ - | $ 458,826 | $ (2,447) | $ 927,948 |

The components of accumulated other comprehensive income (loss) (OCI) as of October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 |
|---|---|---|
| Hedging activities of equity method investments | $ (2,447) | $ 670 |

See notes to consolidated financial statements.

Notes to Consolidated Financial Statements

## 1. Summary of Significant Accounting Policies

### A. Operations and Principles of Consolidation.

Piedmont is an energy services company primarily engaged in the distribution of natural gas to residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. Our utility operations are regulated by three state regulatory commissions. For further information on regulatory matters, see Note 2 to the consolidated financial statements.

The consolidated financial statements reflect the accounts of Piedmont and its wholly owned subsidiaries. Investments in non-utility activities are accounted for under the equity method as we do not have controlling voting interests or otherwise exercise control over the management of such companies. Our ownership interest in each entity is recorded in "Equity method investments in non-utility activities" in the consolidated balance sheets. Earnings or losses from equity method investments are recorded in "Income from equity method investments" in the consolidated statements of income. For further information on equity method investments, see Note 11 to the consolidated financial statements. Revenues and expenses of all other non-utility activities are included in "Non-operating income" in the consolidated statements of income. Inter-company transactions have been eliminated in consolidation where appropriate; however, we have not eliminated inter-company profit on sales to affiliates and costs from affiliates in accordance with accounting regulations prescribed under rate-based regulation.

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated through the filing date of this Form 10-K. There are no subsequent events that had a material impact on our financial position, results of operations or cash flows. For further information, see Note 15 to the consolidated financial statements.

### B. Rate-Regulated Basis of Accounting.

Our utility operations are subject to regulation with respect to rates, service area, accounting and various other matters by the regulatory commissions in the states in which we operate. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying these regulations, we capitalize certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to utility customers in future periods.

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period the rates are in effect. As such, all of our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that accounting for the effects of regulation were no longer applicable, we would recognize a write-off of the regulatory assets and regulatory liabilities that would result in an adjustment to net income. Our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate. It is our opinion that all regulatory assets are recoverable in future rate proceedings; therefore, we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a future rate recovery proceeding.

Regulatory assets and liabilities in the consolidated balance sheets as of October 31, 2009 and 2008 are presented below.

| In thousands | 2009 | 2008 |
|---|---|---|
| Regulatory Assets: | | |
| Unamortized debt expense | $ 9,177 | $ 9,915 |
| Amounts due from customers | 196,130 | 181,745 |
| Environmental costs * | 6,205 | 5,819 |
| Demand-side management costs * | 474 | 1,608 |
| Deferred operations and maintenance expenses * | 8,816 | 9,301 |
| Deferred pipeline integrity expenses * | 6,467 | 6,008 |
| Deferred pension and other retirement benefits costs * | 15,535 | 12,558 |
| Amounts not yet recognized as a component of pension and other retirement benefits costs | 76,905 | 28,732 |
| Regulatory cost of removal asset | 16,293 | 6,398 |
| Other * | 1,541 | 1,121 |
| Total | $ 337,543 | $ 263,205 |
| Regulatory Liabilities: | | |
| Regulatory cost of removal obligations | $ 385,624 | $ 359,302 |
| Deferred income taxes | 23,699 | 24,316 |
| Amounts not yet recognized as a component of pension and other retirement benefits costs* | - | 66 |
| Total | $ 409,323 | $ 383,684 |

* Regulatory assets are included in "Other" in "Noncurrent Assets" and regulatory liabilities are included in "Other" in "Noncurrent Liabilities" in the consolidated balance sheets.

As of October 31, 2009, we had regulatory assets totaling $4.3 million on which we do not earn a return during the recovery period. The original amortization periods for these assets range from 3 to 15 years and, accordingly, $.04 million will be fully amortized by 2010, $3.6 million will be fully amortized by 2011 and the remaining $.7 million will be fully amortized by 2018. We have $47.9 million related to unrealized mark-to-market amounts on which we do not earn a return until they are recorded in interest-bearing amounts due to/from customer accounts when realized and $76.9 million of regulatory postretirement assets, $16.3 million of asset retirement obligations (AROs) and $5.9 million of estimated environmental costs on which we do not earn a return.

C. Utility Plant and Depreciation.

Utility plant is stated at original cost, including direct labor and materials, allocable overhead charges and allowance for funds used during construction (AFUDC). The portion of AFUDC attributable to borrowed funds is shown as a reduction of "Utility Interest Charges" in the consolidated statements of income. Any portion of AFUDC attributable to equity funds would be included in "Other Income (Expense)" in the consolidated statements of income. The costs of property retired are removed from utility plant and charged to accumulated depreciation. AFUDC for the years ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| AFUDC | $ 2,298 | $ 4,002 | $ 3,799 |

In March 2009, we deferred the development and construction of our previously announced liquefied natural gas (LNG) peak storage facility in Robeson County, North Carolina based on revised growth projections. Based on our current growth projections, we may resume development of the project in 2011 to prepare for construction in 2012 in order to provide service in 2015. In accordance with utility accounting practice, we have classified expenditures associated with the LNG facility as "Plant held for future use" in the consolidated balance sheets. The amount classified as held for future use includes capitalized charges for the AFUDC through the date the amounts were transferred to plant held for future use from construction work in progress.

We compute depreciation expense using the straight-line method over periods ranging from four to 88 years. The composite weighted-average depreciation rates were 3.25% for 2009, 3.23% for 2008 and 3.23% for 2007.

Depreciation rates for utility plant are approved by our regulatory commissions. In North Carolina, we are required to conduct a depreciation study every five years and propose new depreciation rates for approval. Our last depreciation study was completed in 2004, and new depreciation rates were approved effective November 1, 2005. No such five-year requirement exists in South Carolina or Tennessee; however, we periodically propose revised rates in those states based on depreciation studies. We collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation. Our approved depreciation rates are comprised of two components, one based on average service life and one based on cost of removal for certain regulated properties. Therefore, through depreciation expense, we accrue estimated non-legal costs of removal on any depreciable asset that includes cost of removal in its depreciation rate.

D. Asset Retirement Obligations.

The accounting guidance for AROs addresses the financial accounting and reporting for AROs associated with the retirement of long-lived assets that result from the acquisition, construction, development and operation of the assets. The accounting guidance requires the recognition of the fair value of a liability for AROs in the period in which the liability is incurred if a reasonable estimate of fair value can be made. We have determined that AROs exist for our underground mains and services.

In accordance with long-standing regulatory treatment, our depreciation rates are comprised of two components, one based on average service life and one based on cost of removal, as stated above. We collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation. These removal costs are non-legal obligations as defined by the accounting guidance. Because these estimated removal costs meet the requirements of rate regulated accounting guidance, we have accounted for these non-legal asset removal obligations as a regulatory liability. We have reclassified the estimated non-legal asset removal obligations from "Accumulated depreciation" to "Cost of removal obligations" in "Noncurrent Liabilities" in our consolidated balance sheets. In the rate setting process, the liability for non-legal costs of removal is treated as a reduction to the net rate base upon which the regulated utility has the opportunity to earn its allowed rate of return.

In 2006, we applied the accounting guidance for conditional AROs that requires recognition of a liability for the fair value of conditional AROs when incurred if the liability can be reasonably estimated. AROs will be capitalized concurrently by increasing the carrying amount of the related asset by the same amount as the liability. In periods subsequent to the initial measurement, any changes in the liability resulting from the passage of time (accretion) or due to the revisions of either timing or the amount of the originally estimated cash flows to settle conditional AROs must be recognized. The estimated cash flows to settle conditional AROs are discounted using the credit adjusted risk-free rate. The estimate was calculated using a time value weighted average credit adjusted risk-free rate. Any accretion will not be reflected in the income statement as we have received regulatory treatment for deferral as a regulatory asset with netting against a regulatory liability. We have recorded a liability on our distribution and transmission mains and services.

The cost of removal obligations recorded in our consolidated balance sheets as of October 31, 2009 and 2008 are presented below.

| In thousands | 2009 | 2008 |
|---|---|---|
| Regulatory non-legal asset removal obligations | $ 385,624 | $ 359,302 |
| Conditional AROs | 23,331 | 8,148 |
| Total cost of removal obligations | $ 408,955 | $ 367,450 |

A reconciliation of the changes in conditional AROs for the year ended October 31, 2009 and 2008 is presented below.

| In thousands | 2009 | 2008 |
|---|---|---|
| Beginning of period | $ 8,148 | $ 17,659 |
| Liabilities incurred during the period | 1,368 | 2,004 |
| Liabilities settled during the period | (1,480) | (1,358) |
| Accretion | 702 | 1,104 |
| Adjustment to estimated cash flows * | 14,593 | (11,261) |
| End of period | $ 23,331 | $ 8,148 |

* Adjustment is primarily due to the change in the credit adjusted risk-free rate from 6.24% as of October 31, 2007 to 8.62% as of October 31, 2008 to the weighted average of 5.87% as of October 31, 2009.

E. Trade Accounts Receivable and Allowance for Doubtful Accounts.

Trade accounts receivable consist of natural gas sales and transportation services, merchandise sales and service work. We maintain an allowance for doubtful accounts, which we adjust periodically, based on the aging of receivables and our historical and projected charge-off activity. Our estimate of recoverability could differ from actual experience based on customer credit issues, the level of natural gas prices and general economic conditions. Pursuant to orders issued by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), we are authorized to recover all uncollected gas costs through the purchased gas adjustment (PGA). As a result, only the portion of accounts written off relating to the non-gas costs, or margin, is included in base rates and, accordingly, only this portion is included in the provision for uncollectibles expense. In Tennessee, to the extent that the gas cost portion of net write-offs for a fiscal year is less than the gas cost portion included in base rates, the difference would be refunded to customers through the Actual Cost Adjustment (ACA) filings. Merchandise receivables due beyond one year are included in "Other" in "Noncurrent Assets" in the consolidated balance sheets.

Our principal business activity is the distribution of natural gas. We believe that we have provided an adequate allowance for any receivables which may not be ultimately collected. As of October 31, 2009 and 2008, our trade accounts receivable consisted of the following.

| In thousands | 2009 | 2008 |
|---|---|---|
| Gas receivables | $ 69,386 | $ 81,234 |
| Merchandise and jobbing receivables | 2,583 | 2,178 |
| Allowance for doubtful accounts | (990) | (1,066) |
| Trade accounts receivable | $ 70,979 | $ 82,346 |

A reconciliation of the changes in the allowance for doubtful accounts for the years ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Balance at beginning of year | $ 1,066 | $ 544 | $ 1,239 |
| Additions charged to uncollectibles expense | 5,570 | 5,308 | 4,981 |
| Accounts written off, net of recoveries | (5,646) | (4,786) | (5,676) |
| Balance at end of year | $ 990 | $ 1,066 | $ 544 |

F. Goodwill, Equity Method Investments and Long-Lived Assets.

All of our goodwill is attributable to the regulated utility segment. We annually evaluate goodwill for impairment on October 31, or more frequently if impairment indicators arise during the year. An impairment charge would be recognized if the carrying value of the reporting unit, including goodwill, exceeded its fair value.

Our annual goodwill impairment assessment was performed at October 31, 2009, and we determined that there was no impairment to the carrying value of our goodwill. No impairment has been recognized during the years ended October 31, 2009, 2008 and 2007.

We review our equity method investments and long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. There were no events or circumstances during the years ended October 31, 2009, 2008 and 2007 that resulted in any impairment charges. For further information on equity method investments, see Note 11 to the consolidated financial statements.

G. Unamortized Debt Expense.

Unamortized debt expense consists of costs, such as underwriting and broker dealer fees, discounts and commissions, legal fees, accountant fees, registration fees and rating agency fees, related to issuing long-term debt and the short-term credit facility. We amortize long-term debt expense on a straight-line basis, which approximates the effective interest method, over the life of the related debt which has lives ranging from 10 to 30 years. We amortize short-term debt expense over the life of the credit facility which is five years.

H. Inventories.

We maintain gas inventories on the basis of average cost. Injections into storage are priced at the purchase cost at the time of injection, and withdrawals from storage are priced at the weighted average purchase price in storage. The cost of gas in storage is recoverable under rate schedules approved by state regulatory commissions. Inventory activity is subject to regulatory review on an annual basis in gas cost recovery proceedings.

We utilize asset management agreements with counterparties for certain natural gas storage and transportation assets. At October 31, 2009, such counterparties held natural gas storage assets, included in "Prepayments" in the consolidated balance sheets, with a value of $40.2 million through capacity release and agency relationships. Under the terms of the asset management agreements, we receive capacity and storage asset management fees. The asset management agreements expire at various times through March 31, 2010.

Materials, supplies and merchandise inventories are valued at the lower of average cost or market and removed from such inventory at average cost.

I. Deferred Purchased Gas Adjustments.

Rate schedules for utility sales and transportation customers include PGA provisions that provide for the recovery of prudently incurred gas costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas. Under PGA provisions, charges to cost of gas are based on the amount recoverable under approved rate schedules. By jurisdiction, differences between gas costs incurred and gas costs billed to customers are deferred and included in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets. We review gas costs and deferral activity periodically and, with regulatory commission approval, increase rates to collect under-recoveries or decrease rates to refund over-recoveries over a subsequent period.

J. Marketable Securities.

We have marketable securities that are invested in money market and mutual funds that are liquid and actively traded on the exchanges. These securities are assets that are held in a rabbi trust established for our deferred compensation plans that became effective on January 1, 2009. For further information on the deferred compensation plans, see Note 8 to the consolidated financial statements.

We have classified these marketable securities as trading securities since their inception as the assets are held in a rabbi trust. Trading securities are recorded at fair value on the consolidated balance sheets with any gains or losses recognized currently in earnings. We do not intend to engage in active trading of the securities, and participants in the deferred compensation plans may redirect their investments at any time. At this date, no participant has announced a retirement date or has elected to receive the deferred compensation in accordance with the terms of the plans. As such, we have matched the asset with the deferred compensation liability and have recorded it as a noncurrent asset.

The money market investments in the trust approximate fair value due to the short period of time to maturity. The fair values of the equity securities are based on quoted market prices as traded on the exchanges. The composition of these securities as of October 31, 2009 is as follows.

| In thousands | Cost | Fair Value |
|---|---|---|
| Money markets | $ 169 | $ 169 |
| Mutual funds | 205 | 272 |
| Total trading securities | $ 374 | $ 441 |

K. Taxes.

Deferred income taxes are determined based on the estimated future tax effects of differences between the book and tax basis of assets and liabilities. Deferred taxes are primarily attributable to utility plant, deferred gas costs, revenues and cost of gas, equity method investments, benefit of loss carryforwards and employee benefits and compensation. We have provided valuation allowances to reduce the carrying amount of deferred tax assets to amounts that are more likely than not to be realized. To the extent that the establishment of deferred income taxes is different from the recovery of taxes through the ratemaking process, the differences are deferred in accordance with rate-regulated accounting provisions, and a regulatory asset or liability is recognized for the impact of tax expenses or benefits that will be collected from or refunded to customers in different periods pursuant to rate orders. We amortize deferred investment and energy tax credits to income over the estimated useful lives of the property to which the credits relate.

Excise taxes, sales taxes and franchises fees separately stated on customer bills are recorded on a net basis as liabilities payable to the applicable jurisdictions. All other taxes other than income taxes are recorded as general taxes. General taxes consist of property taxes, payroll taxes, Tennessee gross receipt taxes, franchise taxes, tax on company use, public utility fees and other miscellaneous taxes.

L. Revenue Recognition.

Utility sales and transportation revenues are based on rates approved by state regulatory commissions. Base rates charged to jurisdictional customers may not be changed without formal approval by the regulatory commission in that jurisdiction; however, the wholesale cost of gas component of rates may be adjusted periodically under PGA provisions. In South Carolina and Tennessee, a weather normalization adjustment (WNA) is calculated for residential and commercial customers during the winter period November through March. The WNA is designed to offset the impact that warmer-than-normal or colder-than-normal weather has on customer billings during the winter season. In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The gas cost portion of our costs is recoverable through PGA procedures and is not affected by the WNA or the margin decoupling mechanism.

Revenues are recognized monthly on the accrual basis, which includes estimated amounts for gas delivered to customers but not yet billed under the cycle-billing method from the last meter reading date to month end. The unbilled revenue estimate reflects factors requiring judgment related to estimated usage by customer class, changes in weather during the period and the impact of the WNA or margin decoupling mechanism, as applicable.

Secondary market revenues are recognized when the physical sales are delivered based on contract or market prices. See Note 2 regarding revenue sharing of secondary market transactions.

Utility sales, transportation and secondary market revenues are reported on a net basis. For further information, see Note 1.K to the consolidated financial statements.

M. Earnings Per Share.

We compute basic earnings per share (EPS) using the weighted average number of shares of common stock outstanding during each period. A reconciliation of basic and diluted EPS for the years ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands except per share amounts | 2009 | 2008 | 2007 |
|---|---|---|---|
| Net Income | $ 122,824 | $ 110,007 | $ 104,387 |
| Average shares of common stock outstanding for basic earnings per share | 73,171 | 73,334 | 74,250 |
| Contingently issuable shares under the Executive Long-Term Incentive Plan and Incentive Compensation Plan | 290 | 278 | 222 |
| Average shares of dilutive stock | 73,461 | 73,612 | 74,472 |
| Earnings Per Share: | | | |
| Basic | $ 1.68 | $ 1.50 | $ 1.41 |
| Diluted | $ 1.67 | $ 1.49 | $ 1.40 |

N. Statements of Cash Flows.

For purposes of reporting cash flows, we consider instruments purchased with an original maturity at date of purchase of three months or less to be cash equivalents.

O. Use of Estimates.

We make estimates and assumptions when preparing the consolidated financial statements. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

P. Recently Issued Accounting Guidance.

We adopted the Financial Accounting Standards Board (FASB) guidance related to the FASB Accounting Standards Codification (ASC) and the Hierarchy of Generally Accepted Accounting Principles (GAAP). This statement identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are prepared in conformity with GAAP in the United States of America. This statement replaces prior guidance related to the hierarchy of GAAP and establishes the FASB ASC as the source of authoritative accounting principles by the FASB. Rules and interpretative releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for all SEC registrants. The adoption of this guidance did not have any impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued guidance related to fair value measurements and disclosures. In November 2007, the FASB delayed the implementation of the fair value guidance for one year only for other nonfinancial assets and liabilities. This guidance provided enhanced direction for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) the measurement of assets or liabilities at fair value, but does not expand the use of fair value measurement to any new circumstances. We adopted the fair value guidance on

November 1, 2008 for our financial assets and liabilities, which consist primarily of derivatives that we record on the consolidated balance sheets in accordance with derivative accounting standards. We adopted the additional fair value guidance on November 1, 2009 for our nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis, such as the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets and long-lived assets impairment tests. The adoption of the fair value guidance for our financial assets and liabilities had no impact on our financial position, results of operations or cash flows. For additional information regarding fair value measurements, see Note 6 to the consolidated financial statements.

In February 2007, the FASB issued guidance related to the fair value measurement of financial instruments that provides companies with an option to report selected financial assets and liabilities at fair value. Its objective is to reduce the complexity in accounting for financial instruments and to mitigate the volatility in earnings caused by measuring related assets and liabilities differently. Although the guidance related to the fair value measurement of financial instruments does not eliminate disclosure requirements included in other accounting standards, it does establish additional presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. This guidance is effective for financial statements issued for fiscal years beginning after November 15, 2007, with early adoption permitted for an entity that has elected also to apply the fair value guidance early. Accordingly, we adopted guidance related to the fair value measurement of selected financial assets and liabilities for our fiscal year beginning November 1, 2008 and did not elect the option to measure any applicable financial assets or liabilities at fair value pursuant to those provisions.

In April 2007, the FASB issued guidance related to "Offsetting of Amounts Related to Certain Contracts," to replace the terms conditional contracts and exchange contracts with the term derivative instruments. The new guidance permits a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance is effective for fiscal years beginning after November 15, 2007, with early application permitted. Accordingly, we have evaluated the impacts of the right to offset fair value amounts pursuant to the new guidance for our fiscal year beginning November 1, 2008. Our policy has been to present our positions, exclusive of any receivable or payable, with the same counterparty on a net basis; however, we elected "not to net" under the new guidance and have reflected reclassifications on our statement of financial position.

In December 2007, the FASB issued new accounting guidance related to business combinations which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date at fair value. This guidance changes the accounting for business combinations in various areas, including contingency consideration, preacquistion contingencies, transaction costs and restructuring costs. In addition, changes in the acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. We will apply the provisions of this guidance to any acquisitions we may complete after November 1, 2009.

In March 2008, the FASB issued guidance related to disclosures about derivative instruments and hedging activities by requiring expanded qualitative, quantitative and credit-risk disclosures about derivative instruments and hedging activities, but without changing the scope or accounting under derivatives and hedging and the related accounting interpretations. The guidance requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. The guidance also amended the disclosure requirements to clarify that derivative instruments are subject to concentration-of-credit-risk disclosures. The guidance is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early adoption permitted. We adopted the new guidance on February 1, 2009. Since only additional disclosures concerning derivatives and hedging activities were required, there was no impact on our financial position, results of operations, or cash flows.

In December 2008, the FASB issued new accounting guidance for employers' disclosures about plan assets of defined benefit pension and other postretirement plans. This guidance requires that employers provide more transparency about the assets held by retirement plans or other postretirement employee benefit plans, the concentration of risk in those plans and information about the fair value measurements of plan assets similar to the disclosures required by the fair value guidance. The guidance is effective for fiscal years ending after December 15, 2009, with earlier application permitted. Since only additional disclosures about plan assets of defined benefit pension and other postretirement plans are required, it is not expected to have a material impact on our financial position, results of operations or cash flows. We will adopt the guidance on benefit plan assets during our fiscal year ending October 31, 2010.

In April 2009, the FASB issued additional guidance related to interim disclosures about fair values of financial instruments that requires publicly traded companies to disclose the fair value of financial instruments during interim reporting in addition to the information provided annually. The guidance was effective for periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the guidance for our quarter ended April 30, 2009. The adoption had no impact on our consolidated financial statements. Comparative information is not required at initial adoption. The disclosure requirements are presented in "Fair Value Measurements" in Note 6 to the consolidated financial statements.

Also in April 2009, the FASB issued guidance for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying transactions that are not orderly. We adopted the guidance effective for our quarter ended April 30, 2009, as concurrent adoption is required with the early adoption of the interim reporting fair value disclosure guidance. The adoption had no impact on our consolidated financial statements.

In May 2009, the FASB issued new guidance related to management's review of subsequent events. The guidance is effective for interim and annual periods ending after June 15, 2009. We adopted the guidance for the period ended July 31, 2009. This guidance establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before the date that the financial statements are issued or are available to be issued. It requires disclosure of the date through which an entity has evaluated subsequent events. Such disclosure is included in Note 15 to the consolidated financial statements. It had no impact on our financial position, results of operations or cash flows as the result of our evaluation.

2. Regulatory Matters

Our utility operations are regulated by the NCUC, PSCSC and Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are also regulated by the NCUC as to the issuance of securities.

In March 2008, we filed a general rate case proceeding with the NCUC requesting an increase in rates and charges for all customers to produce overall increased annual revenues of $40.5 million, or 4% above the current annual revenues. In October 2008, the NCUC approved a settlement between us, the North Carolina Public Staff and all intervening parties with the exception of the North Carolina Attorney General's office, in which the parties agreed to an annual revenue increase of $15.7 million and the continuation of the margin decoupling mechanism that provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. Initially, the margin decoupling mechanism was experimental for a three-year period beginning in 2005, subject to semi-annual reviews and approval for extension in a future general rate case. In addition to the revenue increase, the stipulation also included cost allocation and rate design changes under our existing rate schedules, approval to implement energy conservation and efficiency programs of $1.3 million annually with appropriate cost recovery mechanisms and changes to existing service regulations and tariffs. The new rates became effective November 1, 2008.

Since the inception of the North Carolina energy conservation program on November 1, 2005 where we allocated $.5 million to energy conservation program funding and shared the first $3 million of the margin adjustment that was non-weather related, we have incurred charges of $6.4 million for the benefit of residential and commercial customers. The charges consist of $3.75 million for the funding of conservation programs in North Carolina, $2.25 million for the reduction of residential and commercial customer rates in North Carolina and $.4 million for interest accruals on the conservation funding and reduction of customer rates. At October 31, 2009 and 2008, we had liabilities for the conservation programs of $1.1 million and $1.3 million, respectively.

The North Carolina General Assembly enacted the Clean Water and Natural Gas Critical Needs Act of 1998 which provided for the issuance of $200 million of general obligation bonds of the state for the purpose of providing grants, loans or other financing for the cost of constructing natural gas facilities in unserved areas of North Carolina. In 2000, the NCUC issued an order awarding Eastern North Carolina Natural Gas Company (EasternNC) an exclusive franchise to provide natural gas service to 14 counties in the eastern-most part of North Carolina that had not been able to obtain gas service because of the relatively small population of those counties and the resulting uneconomic feasibility of providing service and granted $38.7 million in state bond funding. In 2001, the NCUC issued an order granting EasternNC an additional $149.6 million, for a total of $188.3 million. With a 2003 acquisition and subsequent merger of EasternNC into our regulated utility segment, we are required to provide an accounting of the operational feasibility of this area to the NCUC every two years. Should this operational area become economically feasible and generate a profit, we would begin to repay the state bond funding.

The NCUC had allowed EasternNC to defer its operations and maintenance expenses during the first eight years of operation or until the first rate case order, whichever occurred first, with a maximum deferral of $15 million. The deferred amounts accrued interest at a rate of 8.69% per annum. In December 2003, the NCUC confirmed that these deferred expenses should be treated as a regulatory asset for future recovery from customers to the extent they are deemed prudent and proper. As a part of the 2005 general rate case proceeding, deferral ceased on October 31, 2005, and the balance in the deferred account as of June 30, 2005, $7.9 million, including accrued interest, is being amortized over 15 years beginning November 1, 2005. Under the settlement of the 2008 general rate proceeding, the unamortized balance of the EasternNC deferred operations and maintenance expenses was $9 million at October 31, 2008. This balance is being amortized over a twelve-year period at a rate of 7.84% per annum.

We incur certain pipeline integrity management costs in compliance with the Pipeline Safety Improvement Act of 1992 and regulations of the United States Department of Transportation. The NCUC approved deferral treatment of these costs applicable to all incremental expenditures beginning November 1, 2004. As a part of the 2005 general rate case, the balance of $.4 million in the deferred account as of June 30, 2005 was amortized over three years beginning November 1, 2005, and subsequent expenditures that totaled $4.3 million as of October 31, 2007 were deferred. Under the settlement of the 2008 general rate proceeding, the pipeline integrity management costs incurred between July 1, 2005 and June 30, 2008 of $4.6 million are being amortized over a three-year period beginning November 1, 2008. The existing regulatory asset treatment for ongoing pipeline integrity management costs will continue until another recovery mechanism is established in a future rate proceeding. The balance as of October 31, 2009 that is not being amortized that is subject to a future rate proceeding is $3.4 million.

We currently operate under the Natural Gas Rate Stabilization Act (RSA) of 2005 in South Carolina. The law provides electing natural gas utilities, including Piedmont, with a mechanism for the regular, periodic and more frequent (annual) adjustment of rates which is intended to: (1) encourage investment by natural gas utilities, (2) enhance economic development efforts, (3) reduce the cost of rate adjustment proceedings and (4) result in smaller but more frequent rate changes for customers. If the utility elects to operate under the RSA, the annual filing will provide that the utility's rate of return on equity will remain within a 50-basis point band above or below the current allowed rate of return on equity.

In June 2007, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2007 and a cost and revenue study as permitted by the RSA requesting no change in margin. In October 2007, the PSCSC issued an order approving a settlement between us, the Office of Regulatory Staff (ORS) and the South Carolina Energy Users Committee (SCEUC) that resulted in a $2.5 million annual decrease in margin based on a return of equity of 11.2%. The new rates were effective November 1, 2007.

In June 2008, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2008 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in the October 2007 order. In the filing, we requested an increase in annual margin of $2 million. In October 2008, the PSCSC issued an order approving a settlement between us, the ORS and the SCEUC that resulted in a $1.5 million annual decrease in margin based on a return on equity of 11.2%, effective November 1, 2008.

In June 2009, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2009 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in the October 2008 order. In the filing, we requested an increase in annual margin of $4.1 million. In October 2009, the PSCSC issued an order approving a settlement between us, the ORS and the SCEUC that resulted in a $1.1 million annual increase in margin based on a return on equity of 11.2%, effective November 1, 2009.

The NCUC and the PSCSC regulate our gas purchasing practices under a standard of prudence and audit our gas cost accounting practices. The TRA regulates our gas purchasing practices under a gas supply incentive program which compares our actual costs to market pricing benchmarks. As part of this jurisdictional oversight, all three states address our gas supply hedging activities. Additionally, North Carolina and South Carolina allow for recovery of uncollectible gas costs through the PGA. The portion of uncollectibles related to gas costs is recovered through the deferred account and only the non-gas costs, or margin, portion of uncollectibles is included in base rates and uncollectibles expense. In Tennessee, to the extent that the gas cost portion of net write-offs for a fiscal year is less than the gas cost portion included in base rates, the difference would be refunded to customers through the ACA filings.

In North Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. Costs have never been disallowed on the basis of prudence.

In August 2007, the NCUC approved our accounting for gas costs during the twelve months ended May 31, 2006, with adjustments agreed to by us as a result of the North Carolina Public Staff's audit of the 2006 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery. In this order, the NCUC also required us to discontinue the accounting practice of capitalizing and amortizing storage demand charges, effective no later than November 1, 2007. This action resulted in a margin decrease of $5.4 million in 2007.

During 2007, under the provisions of the August 2007 NCUC order, we recorded as restricted cash $2.2 million, including interest, of supplier refunds. In September 2007, we petitioned the NCUC for authority to liquidate all certificates of deposit and similar investments that held any supplier refunds due to customers. In October 2007, the NCUC approved the transfer of these restricted funds to the North Carolina deferred account. The various certificates of deposit matured by January 31, 2008.

In November 2007, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2007, with adjustments agreed to by us as a result of the North Carolina Public Staff's audit of the 2007 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In February 2009, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2008, with adjustments agreed to by us as a result of the North Carolina Public Staff's audit of the 2008 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In August 2009, we filed testimony in North Carolina in support of our gas cost purchasing and accounting practices for the twelve months ended May 31, 2009. A hearing was held on October 6, 2009 and testimony was submitted by us and the North Carolina Public Staff with agreed upon adjustments for the 2009 gas cost review period. We are unable to predict the outcome of this proceeding at this time.

Our gas cost hedging plan for North Carolina is designed for the purpose of cost stabilization, targets a percentage range of annual normalized sales volumes for North Carolina and operates using historical pricing indices that are tied to future projected gas prices as traded on a national exchange. Unlike South Carolina as discussed below, recovery of costs associated with the North Carolina hedging plan is not pre-approved by the NCUC, and the costs are treated as gas costs subject to the annual gas cost prudence review. Any gain or loss recognition under the hedging program are deemed to be reductions in or additions to gas costs, respectively, which, along with any hedging expenses, are flowed through to North Carolina customers in rates. The gas cost review orders issued August 2007, November 2007 and February 2009 found our hedging activities during the three review periods to be reasonable and prudent. In 2009, as a part of our North Carolina annual cost review proceeding for the twelve months ended May 31, 2009, we and the North Carolina Public Staff agreed to an adjustment of $1.1 million related to hedging activity as reflected in "Amounts due from customers." This agreement is subject to approval by the NCUC.

In South Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. Costs have never been disallowed on the basis of prudence.

In May 2008, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2007.

In August 2008, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2008.

In August 2009, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2009.

The PSCSC has approved a gas cost hedging plan for the purpose of cost stabilization for South Carolina customers. The plan targets a percentage range of annual normalized sales volumes for South Carolina and operates using historical pricing indices that are tied to future projected gas prices as traded on a national exchange. All properly accounted for costs incurred in accordance with the plan are deemed to be prudently incurred and are recovered in rates as gas costs. Any gain or loss recognition under the hedging program are deemed to be reductions in or additions to gas costs, respectively, and are flowed through to South Carolina customers in rates.

In October 2009, we filed a petition with the PSCSC requesting approval to offer three energy efficiency programs to residential and commercial customers. The proposed programs in South Carolina are designed to promote energy conservation and efficiency by residential and commercial customers and are similar to approved energy efficiency programs in North Carolina. We propose to spend $.4 million annually on these programs, with full ratepayer recovery of program costs. A hearing has been scheduled for February 11, 2010. We are unable to predict the outcome of this proceeding at this time.

In Tennessee, the Tennessee Incentive Plan (TIP) replaced annual prudence reviews under the ACA mechanism in 1996 by benchmarking gas costs against amounts determined by published market indices and by sharing secondary market (capacity release and off-system sales) activity performance. In July 2005, in the order approving our 2004 TIP filing, the TRA established a separate docket to address issues raised by the Tennessee Consumer Advocate Staff and the TRA Staff related to the breadth of secondary market activities covered by the TIP, the method for selecting the independent consultant to review performance under the TIP, and the procedures utilized with respect to requests for proposal. In October 2007, the TRA approved our settlement with the staff of the TRA and the Tennessee Consumer Advocate Staff modifying our TIP with an effective date of July 1, 2006. The modifications clarify and simplify the calculation of allocated gains and losses to ratepayers and shareholders by adopting a uniform 75/25 sharing ratio, maintaining the $1.6 million annual incentive cap on gains and losses, improving the transparency of plan operations by an agreed to request for proposal procedures for asset management transactions and providing for a triennial review of TIP operations by an independent consultant.

We filed an annual report for the twelve months ended December 31, 2006 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In June 2008, the TRA staff filed its final audit report, with which we concurred. In August 2008, the TRA issued an order adopting all findings from the staff audit. The order included cost of gas adjustments for the calendar year 2006 review period. There was no material impact from these gas cost adjustments.

In December 2008, we filed an annual report for the twelve months ended December 31, 2007 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In April 2009, the TRA staff filed its final audit report, with which we concurred. In May 2009, the TRA issued an order adopting all findings from the staff audit. The order included cost of gas adjustments for the calendar year 2007 review period. There was no material impact from these gas cost adjustments. We were found to be in compliance with the TRA rules in the use of the ACA mechanism.

In July 2009, we filed an annual report for the twelve months ended December 31, 2008 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. We are unable to predict the outcome of this proceeding at this time.

In July 2009, we filed a petition with the TRA requesting approval to decouple residential rates in Tennessee and to offer three energy efficiency programs to residential customers. We are proposing a margin decoupling tracker mechanism that is designed to allow us to recover from our residential customers the approved per customer margin as approved in our last general rate proceeding. The proposed energy efficiency programs in Tennessee are designed to promote energy conservation and efficiency by residential customers and are similar to approved energy efficiency programs in North Carolina. We proposed to initially spend $.5 million annually on these programs with shareholder contributions of $.25 million in year one, $.15 million in year two and $.07 million in year three of the programs. In August 2009, the TRA suspended the tariff and established a contested case to address the filing. A hearing on our requests was held on December 17 – 18, 2009. We are unable to predict the outcome of this proceeding at this time.

Due to the seasonal nature of our business, we contract with customers in the secondary market to sell supply and capacity assets when available. In North Carolina and South Carolina, we operate under sharing mechanisms approved by the NCUC and the PSCSC for secondary market transactions where 75% of the net margins are flowed through to jurisdictional customers in rates and 25% is retained by us. In Tennessee, we operate under the amended TIP where gas purchase benchmarking gains and losses are combined with secondary market transaction gains and losses and shared 75% by customers and 25% by us. Our share of net gains or losses in Tennessee is subject to an overall annual cap of $1.6 million. In all three jurisdictions for the twelve months ended October 31, 2009, we generated $46 million of margin from secondary market activity, $34.5 million of which is allocated to customers as gas cost reductions and $11.5 million as margin allocated to us.

Effective October 31, 2006, the NCUC, the PSCSC and the TRA authorized us to place certain ARO costs in deferred accounts to preserve the regulatory treatment for these costs. This was a result of adopting accounting guidance for conditional AROs.

In August 2007, we filed petitions with the NCUC, the PSCSC and the TRA requesting the ability to place certain defined benefit postretirement obligations related to the implementation of accounting guidance for employers' accounting for defined benefit pension and other postretirement plans in a deferred account instead of OCI. The petitions were approved in all of the jurisdictions.

We currently have commission approval in all three states that place tighter credit requirements on the retail natural gas marketers that schedule gas into our system in order to mitigate the risk exposure to the financial condition of the marketers.

3. Long-Term Debt

All of our long-term debt is unsecured and is issued at fixed rates. Long-term debt as of October 31, 2009 and 2008 is as follows.

| In thousands | 2009 | 2008 |
|---|---|---|
| Senior Notes: | | |
| 8.51%, due 2017 | $ 35,000 | $ 35,000 |
| Medium-Term Notes: | | |
| 7.35%, due 2009 | - | 30,000 |
| 7.80%, due 2010 | 60,000 | 60,000 |
| 6.55%, due 2011 | 60,000 | 60,000 |
| 5.00%, due 2013 | 100,000 | 100,000 |
| 6.87%, due 2023 | 45,000 | 45,000 |
| 8.45%, due 2024 | 40,000 | 40,000 |
| 7.40%, due 2025 | 55,000 | 55,000 |
| 7.50%, due 2026 | 40,000 | 40,000 |
| 7.95%, due 2029 | 60,000 | 60,000 |
| 6.00%, due 2033 | 100,000 | 100,000 |
| Insured Quarterly Notes: | | |
| 6.25%, due 2036 | 197,512 | 199,261 |
| Total | 792,512 | 824,261 |
| Less current maturities | 60,000 | 30,000 |
| Total | $ 732,512 | $ 794,261 |

Current maturities for the next five years ending October 31 and thereafter are as follows.

| In thousands | |
|---|---|
| 2010 | $ 60,000 |
| 2011 | 60,000 |
| 2012 | - |
| 2013 | - |
| 2014 | 100,000 |
| Thereafter | 572,512 |
| Total | $ 792,512 |

We had a shelf registration statement filed with the SEC that could have been used for either the issuance of debt or equity securities that expired on December 1, 2008. The remaining balance of unused long-term financing available under this shelf registration statement at the time of expiration was $109.4 million.

Payments of $1.7 million and $.6 million in 2009 and 2008, respectively, were paid to noteholders of the 6.25% insured quarterly notes based on a redemption right upon the death of the owner of the notes, within specified limitations. In September 2009, the balance of $30 million under our 7.35% medium-term notes became due and was retired.

The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued, with those for the senior notes being the most restrictive. We cannot pay or declare any dividends or make any other distribution on any class of stock or make any investments in subsidiaries or permit any subsidiary to do any of the above (all of the foregoing being "restricted payments"), except out of net earnings available for restricted payments. As of October 31, 2009, our retained earnings were not restricted as the amount available for restricted payments was greater than our actual retained earnings as presented below.

In thousands

| | |
|---|---|
| Amount available for restricted payments | $ 570,422 |
| Retained earnings | 458,826 |

We are subject to default provisions related to our long-term debt and short-term debt. Failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. There are cross-default provisions in all of our debt agreements. As of October 31, 2009, we are in compliance with all default provisions.

4. Short-Term Debt Instruments

We have a syndicated five-year revolving credit facility that expires April 2011 with aggregate commitments totaling $450 million to meet working capital needs. This facility may be increased up to $600 million and includes annual renewal options and letters of credit. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $450 million. The facility provides a line of credit for letters of credit of $5 million, of which $2.4 million and $1.9 million were issued and outstanding at October 31, 2009 and 2008, respectively. These letters of credit are used to guarantee claims from self-insurance under our general liability policies. The credit facility bears interest based on the 30-day LIBOR rate plus from 15 to 35 basis points, based on our credit ratings.

Effective December 3, 2008, we entered into a syndicated seasonal credit facility with aggregate commitments totaling $150 million. Advances under this seasonal facility bore interest at a rate based on the 30-day LIBOR rate plus from 75 to 175 basis points, based on our credit ratings. This seasonal credit facility expired on March 31, 2009. We entered into this facility to provide lines of credit in addition to the syndicated five-year revolving credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements and general corporate needs. This seasonal credit facility replaced the two short-term credit facilities with banks for unsecured commitments totaling $75 million that were effective from October 27 and 29, 2008 through December 3, 2008, bearing interest at the same rate as the seasonal facility.

As of October 31, 2009 and 2008, outstanding short-term borrowings under our syndicated five-year revolving credit facility as included in "Notes payable" in the consolidated balance sheets were $306 million and $406.5 million, respectively, in LIBOR cost-plus loans at a weighted average interest rate of .85% in 2009 and 2.84% in 2008. During the twelve months ended October 31, 2009, short-term borrowings ranged from $131.5 million to $556.5 million, and interest rates ranged from .50% to 2.84%. Our syndicated five-year revolving credit facility's financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%, and our actual ratio was 54% at October 31, 2009.

We have corrected the presentation within the consolidated statements of cash flows for the years ended October 31, 2008 and 2007 to present borrowings and repayments under our syndicated five-year revolving credit facility on a gross basis. Such borrowings and repayments were formerly presented on a net basis. There was no effect on total cash flows from financing activities. The quarterly periods in the year ended October 31, 2009 will be corrected on a prospective basis within the filing of the January 31, April 30 and July 31, 2010 Form 10-Qs.

5. Capital Stock and Accelerated Share Repurchase

Changes in common stock for the years ended October 31, 2009, 2008 and 2007 are as follows.

| In thousands | Shares | Amount |
|---|---|---|
| Balance, October 31, 2006 | 75,464 | $ 532,764 |
| Issued to participants in the Employee Stock Purchase Plan (ESPP) | 34 | 809 |
| Issued to the Dividend Reinvestment and Stock Purchase Plan (DRIP) | 593 | 14,973 |
| Issued to participants in the Executive Long-Term Incentive Plan (LTIP) | 117 | 3,264 |
| Shares repurchased under Common Stock Open Market Repurchase Plan | (150) | (3,953) |
| Shares repurchased under Accelerated Share Repurchase (ASR) Plan | (1,850) | (50,287) |
| Balance, October 31, 2007 | 74,208 | 497,570 |
| Issued to ESPP | 33 | 838 |
| Issued to DRIP | 567 | 14,753 |
| Issued to LTIP | 40 | 1,082 |
| Shares repurchased under Common Stock Open Market Repurchase Plan | (1,000) | (26,139) |
| Shares repurchased under ASR Plan | (602) | (16,539) |
| Balance, October 31, 2008 | 73,246 | 471,565 |
| Issued to ESPP | 37 | 875 |
| Issued to DRIP | 565 | 13,560 |
| Issued to LTIP | 89 | 2,755 |
| Issued to Incentive Compensation Plan (ICP) | 29 | 671 |
| Shares repurchased under ASR Plan | (700) | (17,857) |
| Balance, October 31, 2009 | 73,266 | $ 471,569 |

In June 2004, the Board of Directors approved a Common Stock Open Market Purchase Program that authorized the repurchase of up to three million shares of currently outstanding shares of common stock. We implemented the program in September 2004. We utilize a broker to repurchase the shares on the open market and such shares are cancelled and become authorized but unissued shares available for issuance.

On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the two-for-one stock split in 2004. The Board also approved on that date an amendment of the Common Stock Open Market Purchase Program to provide for the repurchase of up to four million additional shares of common stock to maintain our debt-to-equity capitalization ratios at target levels. These combined actions increased the total authorized share repurchases from three million to ten million shares. The additional four million shares were referred to as our ASR program with an expiration date of December 31, 2010. On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated.

On March 20, 2009, we entered into an ASR agreement with an investment bank to purchase and retire 700,000 shares of our common stock from an investment bank at the closing price of that day of $26.35 per share. Total consideration paid to purchase the shares of $18.4 million was recorded in "Stockholders' equity" as a reduction in "Common stock" in the consolidated balance sheets.

As part of the ASR agreement, we simultaneously entered into a forward sale contract with the investment bank that was expected to mature in approximately 35 trading days. Under the terms of the forward sale contract, the investment bank was required to purchase, in the open market, 700,000 shares of our common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to us. At settlement, we, at our option, were required to either pay cash or issue registered or unregistered shares of our common stock to the investment bank if the investment bank's weighted average purchase price was higher than the initial purchase closing price. The investment bank was required to pay us either cash or shares of our common stock, at our option, if the investment bank's weighted average price for the shares purchased was lower than the initial purchase closing price. At settlement on April 21, 2009, we received cash of $.6 million from the investment bank and recorded this amount in "Stockholders' equity" as an addition to "Common stock" in the consolidated balance sheets. The $.6 million was the difference between the investment bank's weighted average purchase price of $25.6093 less a discount of $.10 for a settlement price of $25.5093 and the initial purchase closing price of $26.35 per share multiplied by 700,000 shares.

As of October 31, 2009, 2.4 million shares of common stock were reserved for issuance as follows.

| In thousands | |
|---|---|
| ESPP | 37 |
| DRIP | - |
| LTIP and ICP | 2,327 |
| Total | 2,364 |

On November 20, 2009, we filed a registration statement with the SEC to register the offering of 2.75 million shares of our common stock under our DRIP for future sales of our common stock under the DRIP. As a result of an administrative error, between December 1, 2008 and November 16, 2009, we sold 568,000 shares of common stock under our DRIP at prices ranging from $21.59 to $31.56. On November 16, 2009, we discovered that the offer and sale of these shares of common stock under the DRIP during this period were not registered under applicable securities laws and were not exempt from registration under those laws, making them unregistered shares. We received $13.6 million in the aggregate from these sales, which was used for financing the construction of additions to our facilities and for general corporate purposes. To ensure compliance with the Securities Act of 1933, as amended, to provide a remedy to any DRIP participant aggrieved by the failure to register and to notify DRIP participants of their rights as generally prescribed by the applicable securities laws, we intend to file a registration statement on Form S-3 to register a rescission offer to DRIP participants for the unregistered shares and to register the unregistered shares. The sale of unregistered shares could also subject us to regulatory sanctions by the SEC or other regulatory authorities that might result in the imposition of civil penalties, which could include fines or a cease and desist order. We have reported these events and are cooperating with the relevant regulatory authorities, including the SEC and NCUC. Although we do not expect any rescissions or regulatory actions to have a material adverse effect on us, we are unable to predict the full consequences of these events and regulatory actions.

## 6. Financial Instruments and Related Fair Value

### Derivative Assets and Liabilities under Master Netting Arrangements

We maintain brokerage accounts to facilitate transactions that support our gas cost hedging plans. Based on the value of our positions in these brokerage accounts and the associated margin requirements, we may be required to deposit cash into these brokerage accounts. We elected "not to net" fair value amounts for our derivative instruments or the fair value of the right to reclaim cash collateral in accordance with accounting guidance and moved to a gross presentation on November 1, 2008. We include amounts recognized for the right to reclaim cash collateral in our current assets and current liabilities. We had the right to reclaim cash collateral of $35.4 million and $67.3 million as of October 31, 2009 and 2008, respectively.

### Fair Value Measurements

In September 2006, the FASB issued guidance related to fair value measurements and disclosures. This guidance provided enhanced direction for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) the measurement of assets or liabilities at fair value, but does not expand the use of fair value measurement to any new circumstances. Under this guidance, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the entity transacts. Fair value should be based on the assumptions market participants would use when pricing the asset or liability. A fair value hierarchy is established for valuation inputs that prioritizes the information used to develop those assumptions into three levels. In November 2007, the FASB delayed the implementation of additional guidance related to other nonfinancial assets and liabilities for one year.

We adopted the fair value guidance on November 1, 2008 for our financial assets and liabilities, which consist primarily of derivatives that we record on the consolidated balance sheets in accordance with derivative accounting standards. The adoption of the fair value guidance for our financial assets and liabilities had no impact on our financial position, results of operations or cash flows. There was no cumulative effect adjustment to retained earnings as a result of the adoption. We adopted the additional fair value guidance for our nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis, such as the initial measurement of an ARO or the use of fair value in goodwill, intangible assets and long-lived assets impairment tests, on November 1, 2009. The adoption had no material impact on our financial position, results of operations or cash flows.

The carrying value of cash and cash equivalents, receivables, notes payable, accounts payable and accrued interest approximates fair value.

We utilize market data or assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally observable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observance of those inputs into the following fair value hierarchy levels as set forth in the fair value guidance.

Level 1

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity has the ability to access as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of financial instruments of exchange-traded derivatives and investments in marketable securities.

Level 2

Level 2 inputs are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly corroborated or observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. We obtain market price data from multiple sources in order to value our Level 2 transactions, and this data is representative of transactions that occurred in the market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded derivatives and values based on other sources. Instruments in this category include non-exchange-traded derivative instruments such as over-the-counter (OTC) options.

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customer's needs. We do not have any material financial assets or liabilities classified as Level 3.

The following table sets forth, by level of the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of October 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their consideration with the fair value hierarchy levels.

Recurring Fair Value Measurements as of October 31, 2009

| In thousands | | Quoted Prices in Active Markets (Level 1) | | Significant Other Observable Inputs (Level 2) | | Significant Unobservable Inputs (Level 3) | | Total Carrying Value |
|---|---|---|---|---|---|---|---|---|
| Assets: | | | | | | | | |
| Derivatives held for distribution operations | $ | 2,559 | $ | - | $ | - | $ | 2,559 |
| Debt and equity securities held as trading securities | | 441 | | - | | - | | 441 |
| Total fair value assets | $ | 3,000 | $ | - | $ | - | $ | 3,000 |
| Liabilities: | | | | | | | | |
| Derivatives held for distribution operations | $ | 30,290 | $ | 313 | $ | - | $ | 30,603 |

The determination of the fair values incorporates various factors required under the fair value guidance. These factors include the credit standing of the counterparties involved, the impact of credit enhancements (such as cash deposits, letters of credit and priority interests) and the impact of our nonperformance risk on our liabilities.

Our utility segment derivative instruments are used in accordance with programs filed or approved with the NCUC, the PSCSC and the TRA to hedge the impact of market fluctuations in natural gas prices. These derivative instruments are accounted for at fair value each reporting period. In accordance with regulatory requirements, the net costs and the gains and losses related to these derivatives are reflected in purchased gas costs and ultimately passed through to customers through our PGA procedures. In accordance with accounting provisions for rate-regulated activities, the unrecovered amounts related to these instruments are reflected as a regulatory asset or liability, as appropriate, in "Amounts due to customers" or "Amounts due from customers" in our consolidated balance sheets. These derivative instruments include exchange-traded and OTC derivative contracts. Exchange-traded contracts are generally based on unadjusted quoted prices in active markets and are classified within Level 1. OTC derivative contracts are valued using broker or dealer quotation services or market transactions in either the listed or OTC markets and are classified within Level 2.

Trading securities include assets in a rabbi trust established for our deferred compensation plans and are included in "Marketable securities, at fair value" in the consolidated balance sheets. Securities classified within Level 1 include funds held in money market and mutual funds which are highly liquid and are actively traded on the exchanges.

In developing the fair value of our long-term debt, we use a discounted cash flow technique, consistently applied, that incorporates a developed discount rate using long-term debt similarly rated by credit rating agencies combined with the U.S. Treasury bench mark with consideration given to maturities, redemption terms and credit ratings similar to our debt issuances. The carrying amount and fair value of our long-term debt, including the current portion, are shown below.

| In thousands | | Carrying Amount | | Fair Value |
|---|---|---|---|---|
| As of October 31, 2009 | $ | 792,512 | $ | 910,310 |
| As of October 31, 2008 | | 824,261 | | 798,057 |

Quantitative and Qualitative Disclosures

We adopted new FASB guidance related to disclosures about derivative instruments and hedging activities for derivatives that we record on the consolidated balance sheets in accordance with derivative accounting standards. The guidance amends derivative accounting standards by requiring expanded qualitative, quantitative and credit-risk disclosures about derivative instruments and hedging activities. The guidance requires specific disclosures regarding how and why an entity uses derivative instruments; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. The guidance also amended the disclosure requirements to clarify that derivative instruments are subject to concentration-of-credit-risk disclosures.

The costs of our financial price hedging options for natural gas and all other costs related to hedging activities of our regulated gas costs are recorded in accordance with our regulatory tariffs approved by our state regulatory commissions, and thus are not accounted for as hedging instruments under derivative accounting standards. As required by the new disclosure guidance, the fair value amounts are presented on a gross basis and do not reflect any netting of asset and liability amounts or cash collateral amounts under master netting arrangements. As of October 31, 2009, our financial options were comprised of both long and short commodity positions. A long position is an option contract (obligation or right) to purchase the commodity at a specified price, while a short position is an option contract (obligation or right) to sell the commodity at a specified price. As of October 31, 2009, we had long gas options of 75.1 million dekatherms and short gas options of 40.9 million dekatherms providing total coverage of 49.7 million dekatherms over the period from December 2009 through November 2010.

The following table presents the fair value and balance sheet classification of our financial options for natural gas as of October 31, 2009.

Fair Value of Derivative Instruments as of October 31, 2009

| In thousands | Balance Sheet Classification | Fair Value |
|---|---|---|
| Derivatives Not Designated as Hedging Instruments under Derivative Accounting Standards: | | |
| Asset Financial Instruments | | |
| Current gas purchase options (December 2009 - November 2010) | Current Assets - Gas purchase options | $ 2,559 |
| Liability Financial Instruments | | |
| Current gas purchase options (December 2009 - November 2010) | Current Liabilities - Gas purchase options | 30,603 |
| Total financial instruments, net | | $ (28,044) |

We purchase natural gas for our regulated operations for resale under tariffs approved by state regulatory commissions. We recover the cost of gas purchased for regulated operations through PGA procedures. Our risk management policies allow us to use financial instruments to hedge commodity price risks, but not for speculative trading. The strategy and objective of our hedging programs is to use these financial instruments to provide protection against significant price increases. Accordingly, the operation of the hedging programs on the regulated utility segment as a result of the use of these financial derivatives generally has no earnings impact.

The following table presents the impact that financial instruments would have had on our consolidated statements of operations for the twelve months ended October 31, 2009, absent the regulatory treatment under our approved PGA procedures.

| In thousands | Amount of (Loss) Recognized on Derivative Instruments | Amount of (Loss) Deferred Under PGA Procedures | Location of (Loss) Recognized through PGA Procedures |
|---|---|---|---|
| Derivatives Not Designated as Hedging Instruments under Derivative Accounting Standards | Twelve Months Ended October 31, 2009 | Twelve Months Ended October 31, 2009 | |
| Gas purchase options | $ (148,461) | $ (147,370) | Cost of Gas |

In Tennessee, the cost of these options and all other costs related to hedging activities up to 1% of total annual gas costs are approved for recovery under the terms and conditions of our TIP approved by the TRA. In South Carolina, the costs of these options are pre-approved by the PSCSC for recovery from customers subject to the terms and conditions of our gas hedging plan approved by the PSCSC. In North Carolina, costs associated with our hedging program are not pre-approved by the NCUC but are treated as gas costs subject to an annual cost review proceeding by the NCUC. In 2009, as a part of our North Carolina annual cost review proceeding for the twelve months ended May 31, 2009, we and the North Carolina Public Staff agreed to an adjustment of $1.1 million related to hedging activity as reflected in "Amounts due from customers." This agreement is subject to approval by the NCUC.

Risk Management

Our OTC derivative financial instruments do not contain material credit-risk-related or other contingent features that could require us to make accelerated payments over and above payments made in the normal course of business when we are in a net liability position. At October 31, 2009, we have five International Swaps and Derivatives Association (ISDA) agreements for the purpose of securing put options as a part of our overall hedging program. The ISDA agreements specify a net liability of $55 million, $50 million, $30 million, $25 million and $2 million before we are obligated to post collateral. The net liability extended under the agreements is a function of the credit rating assigned to us by Standard & Poor's Ratings Services (S&P), which is currently A/stable. In the event of a downgrade in our S&P credit rating to A-, the net liability available to us would decline to $142 million before we would be obligated to post collateral. The aggregate fair value of the derivative instruments that are in a net liability position on October 31, 2009 under one ISDA agreement is $.3 million of a total net authorized liability of $50 million, for which we are not required to post collateral. These instruments are acquired under the provisions of our regulatory tariffs. Therefore, should credit-risk-related factors require us to deposit funds as collateral, these amounts would be treated as costs associated with our hedging programs under the recovery mechanism filed with and allowed by each of our state regulators.

We seek to identify, assess, monitor and manage risk in accordance with defined policies and procedures under an Enterprise Risk Management Policy. In addition, we have an Energy Price Risk Management Committee that monitors compliance with our hedging programs, policies and procedures.

7. Commitments and Contingent Liabilities

Leases

We lease certain buildings, land and equipment for use in our operations under noncancelable operating leases. Operating lease payments for the years ended October 31, 2009, 2008 and 2007 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Operating lease payments | $ 6,173 | $ 5,483 | $ 6,587 |

Future minimum lease obligations for the next five years ending October 31 and thereafter are as follows.

| In thousands | |
|---|---|
| 2010 | $ 5,008 |
| 2011 | 4,335 |
| 2012 | 4,202 |
| 2013 | 3,978 |
| 2014 | 3,914 |
| Thereafter | 5,956 |
| Total | $ 27,393 |

## Long-term contracts

We routinely enter into long-term gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services we need in our business. These commitments include pipeline and storage capacity contracts and gas supply contracts to provide service to our customers and telecommunication and information technology contracts and other purchase obligations. The time periods for pipeline and storage capacity contracts range from one to fourteen years. The time periods for gas supply contracts range from one to three years. The time periods for the telecommunications and technology outsourcing contracts, maintenance fees for hardware and software applications, usage fees, local and long-distance costs and wireless service range from one to three years. Other purchase obligations consist primarily of commitments for pipeline products, vehicles and contractors.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the Federal Energy Regulatory Commission (FERC) in order to maintain our right to access the natural gas storage or the pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the consolidated statements of income as part of gas purchases and included in cost of gas.

As of October 31, 2009, future unconditional purchase obligations for the next five years ending October 31 and thereafter are as follows.

| In thousands | Pipeline and Storage Capacity | Gas Supply | Telecommunications and Information Technology | Other | Total |
|---|---|---|---|---|---|
| 2010 | $ 151,370 | $ 14,929 | $ 15,660 | $ 8,084 | $ 190,043 |
| 2011 | 150,272 | 131 | 5,458 | - | 155,861 |
| 2012 | 146,316 | 48 | 1,908 | - | 148,272 |
| 2013 | 96,138 | 12 | - | - | 96,150 |
| 2014 | 70,898 | - | - | - | 70,898 |
| Thereafter | 325,129 | - | - | - | 325,129 |
| Total | $ 940,123 | $ 15,120 | $ 23,026 | $ 8,084 | $ 986,353 |

## Legal

On July 29, 2009, we settled a pending lawsuit with our SouthStar Energy Services LLC (SouthStar) partner, Georgia Natural Gas Company (GNGC), a wholly-owned subsidiary of AGL Resources, Inc. (AGLR), over whether GNGC's right to purchase our interest was perpetual in nature. Under the terms of the settlement agreement, we will sell half of our 30% membership interest in SouthStar to GNGC effective January 1, 2010 for $57.5 million, retaining a 15% earnings and membership share in SouthStar after the sale. As part of the agreement, GNGC has no further option rights to purchase any portion of our remaining 15% membership interest. The agreement has been approved by both companies' boards of directors and was approved by the Georgia Public Service Commission (Georgia PSC) in October 2009. The lawsuit we filed in the Court of Chancery of the State of Delaware against GNGC was dismissed in October 2009.

Other than described above, we have only routine litigation in the normal course of business.

Letters of Credit

We use letters of credit to guarantee claims from self-insurance under our general liability policies. We had $2.4 million in letters of credit that were issued and outstanding at October 31, 2009. Additional information concerning letters of credit is included in Note 4 to the consolidated financial statements.

Environmental Matters

Our three regulatory commissions have authorized us to utilize deferral accounting in connection with environmental costs. Accordingly, we have established regulatory assets for actual environmental costs incurred and for estimated environmental liabilities recorded.

In October 1997, we entered into a settlement with a third party with respect to nine manufactured gas plant (MGP) sites that we have owned, leased or operated and paid $5.3 million, charged to the estimated environmental liability, that released us from any investigation and remediation liability. Although no such claims are pending or, to our knowledge, threatened, the settlement did not cover any third-party claims for personal injury, death, property damage and diminution of property value or natural resources. On one of these nine properties, we performed additional clean-up activities, including the removal of an underground storage tank, in anticipation of an impending sale.

There are three other MGP sites located in Hickory, North Carolina, Nashville, Tennessee and Anderson, South Carolina that we have owned, leased or operated. In addition to these sites, we acquired the liability for an MGP site located in Reidsville, North Carolina, in connection with the acquisition in 2002 of certain assets and liabilities of North Carolina Services, a division of NUI Utilities, Inc.

As part of a voluntary agreement with the North Carolina Department of Environment and Natural Resources (NCDENR), we started the initial steps for investigating the Hickory, North Carolina MGP site in 2007. Based on a limited site assessment report in 2007, we concluded that gas plant residuals remaining on the Hickory site were thought to be mostly contained within two former tar separators associated with the site's operations. During 2008, more extensive testing was conducted and completed, including soil investigation and phase 1 of the groundwater investigation. The investigation report from these tests was submitted to the NCDENR in the first quarter of fiscal 2009. Based on the report, our estimate of the total cost to remediate the Hickory MGP site is $1 million.

During 2008, we completed the remediation of our MGP site located in Nashville at a cost of $1.4 million. In November 2008, we submitted our final report to the Tennessee Department of Environment and Conservation. We have not yet received the Department's determination as to whether additional steps, if any, are required for the site.

During 2008, we became aware of and began investigating three contaminated areas at our Huntersville LNG facility. The first area of investigation is an area potentially contaminated with trichloroethylene, a chlorinated hydrocarbon used in degreasing operations. At the Huntersville LNG facility, trichloroethylene may have been used to clean equipment. The second area is an area in which molecular sieve was buried and potentially contaminated with hydrocarbons and trichloroethylene. The third area to be potentially remediated is an area that may contain lead contamination. The Huntersville LNG facility was originally coated with lead based paint. As a precautionary measure to ensure that no lead contamination has occurred, we plan on removing all lead based paint from the site and sampling soil around the equipment to ensure that no contamination has occurred. During 2009, our estimate of the total cost to remediate the facility increased from $1.1 million to $1.6 million. In accordance with the deferral accounting authorized by our regulatory commissions, we adjusted the regulatory asset and the estimated liability for this additional $.5 million. We have incurred $.9 million through October 31, 2009.

As of October 31, 2009, our undiscounted environmental liability totaled $3.6 million, and consisted of $2.5 million for the four MGP sites for which we retain remediation responsibility, $.6 million for the LNG facility and $.5 million for five underground storage tanks not yet remediated. We increased the liability in 2008 by $.2 million to reflect the impact of inflation based on the consumer price index. For 2009 there was no impact of inflation to the liability.

As of October 31, 2009, our regulatory assets for unamortized environmental costs totaled $6.2 million. We have not sought recovery of these amounts in our rates. However, we will seek recovery in future rate proceedings.

In connection with the 2003 North Carolina Natural Gas Corporation (NCNG) acquisition, several MGP sites owned by NCNG were transferred to a wholly owned subsidiary of Progress Energy, Inc. (Progress) prior to closing. Progress has complete responsibility for performing all of NCNG's remediation obligations to conduct testing and clean-up at these sites, including both the costs of such testing and clean-up and the implementation of any affirmative remediation obligations that NCNG has related to the sites. Progress' responsibility does not include any third-party claims for personal injury, death, property damage, and diminution of property value or natural resources. We know of no such pending or threatened claims.

In July 2005, we were notified by the NCDENR that we were named as a potentially responsible party for alleged environmental issues associated with an underground storage tank site in Clemmons, North Carolina. We owned and operated this site from March 1986 until June 1988 in connection with a non-utility venture. There have been at least four owners of the site. We contractually transferred any clean-up costs to the new owner of the site when we sold this venture in June 1988. Our current estimate of the cost to remediate the site is approximately $136,400. It is unclear how many of the former owners may ultimately be held liable for this site; however, based on the uncertainty of the ultimate liability, we established a non-regulated environmental liability for $34,100, one-fourth of the estimated cost.

Further evaluation of the MGP sites and the underground storage tank sites could significantly affect recorded amounts; however, we believe that the ultimate resolution of these matters will not have a material adverse effect on our financial position, results of operations or cash flows.

During 2008, through the normal course of an on-going business review, one of our operating districts was found to have coatings on their pipes containing asbestos. We have taken action to educate employees on the hazards of asbestos and to implement procedures for removing these coatings from our pipelines when we must excavate and expose small portions of the pipeline. We continue to determine the impacts and related costs to us, if any, and the impact to employees and contractors, if any.

Other

We entered into a stipulation and agreement with FERC's Office of Enforcement regarding certain instances of alleged non-compliance with FERC's capacity release regulations regarding posting and bidding requirements for short-term releases. The agreement was approved by the FERC and required us, among other matters, to pay a civil penalty in settlement of the matter. The penalty, which was paid in July 2009, did not have a material effect on our financial position, results of operations or cash flows.

8. Employee Benefit Plans

Effective January 1, 2008, we amended our noncontributory defined benefit pension plan, other postretirement employee benefits (OPEB) plan and our 401(k) plans. These amendments applied to nonunion employees and employees covered by the Carolinas bargaining unit contract. Effective January 1, 2009, these same amendments applied to all employees, including those covered by the Nashville, Tennessee bargaining unit contract.

We have a noncontributory defined benefit pension plan for the benefit of eligible employees. An employee became eligible on the January 1 or July 1 following either the date on which he or she attained age 30 or attained age 21 and completed 1,000 hours of service during the 12-month period commencing on the employment date. Plan benefits are generally based on credited years of service and the level of compensation during the five consecutive years of the last ten years prior to retirement or termination during which the participant received the highest compensation. Our policy is to fund the plan in an amount not in excess of the amount that is deductible for income tax purposes. Effective January 1, 2008, the defined benefit pension plan was amended for all employees not covered by the bargaining unit contract in Nashville, Tennessee to close the plan to employees hired after December 31, 2007 and to modify how benefits are accrued in the future for existing employees. Employees hired prior to January 1, 2008 continue to participate in the amended traditional defined benefit pension plan. Employees are vested after five years of service and can be credited with up to a total of 35 years of service. When an employee leaves the company, his benefit payment will be calculated as the greater of the accrued benefit as of December 31, 2007 under the old formula plus the accrued benefit under the new formula for years of service after December 31, 2007, or the benefit for all years of service up to 35 years under the new formula. These amendments were effective on January 1, 2009 for employees covered by the bargaining unit contract in Nashville, Tennessee.

Employees hired or rehired after December 31, 2007 (or December 31, 2008 for employees covered by the bargaining unit contract in Nashville, Tennessee) cannot participate in the amended traditional pension plan but are participants in the new Money Purchase Pension (MPP) plan, a defined contribution pension plan that allows the employee to direct the investments. Eligible employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Under the MPP plan, we annually deposit a percentage of each participant's pay into an account of the MPP plan. This contribution equals 4% of the participant's compensation plus an additional 4% of compensation above the social security wage base. The participant is vested in this plan after three years of service. During the year ended October 31, 2009, we contributed $87,000 to the MPP plan.

We provide certain postretirement health care and life insurance benefits to eligible retirees. The liability associated with such benefits is funded in irrevocable trust funds that can only be used to pay the benefits. Employees are first eligible to retire and receive these benefits at age 55 with ten or more years of service after the age of 45. Employees who met this requirement in 1993 or who retired prior to 1993 are in a "grandfathered" group for whom we pay the full cost of the retiree's coverage and the retiree pays the full cost of dependent coverage. Retirees not in the grandfathered group have 80% of the cost of retiree coverage paid by us, subject to certain annual contribution limits. Retirees are responsible for the full cost of dependent coverage. Effective January 1, 2008 (January 1, 2009 for new employees covered under the bargaining unit contract in Nashville, Tennessee), new employees have to complete ten years of service after age 50 to be eligible for benefits, and no benefits are provided to those employees after age 65 when they are automatically eligible for Medicare benefits to cover health costs. Our OPEB plan includes a defined dollar benefit to pay the premiums for Medicare Part D. Employees who meet the eligibility requirements to retire also receive a life insurance benefit. For employees who retire after July 1, 2005, this benefit is $15,000. The life insurance amount for employees who retired prior to this date was calculated as a percentage of their basic life insurance prior to retirement.

We have pension liabilities related to supplemental executive retirement plans (SERPs) for certain former employees, non-employee directors or the surviving spouse. There are no assets related to the SERPs and no additional benefits accrue to the participants. Payments to the participants are made from operating funds during the year. These nonqualified plans are presented below.

We previously had a SERP covering all officers at the vice president level and above. It provided supplemental retirement income as well as a life insurance benefit for officers to indirectly address the tax code limitations on qualified retirement plans. The level of insurance benefit and target retirement income benefits intended to be provided under the SERP depended upon the position of the officer. The SERP was funded by life insurance policies covering each officer, and the policy was owned exclusively by each officer.

On September 4, 2008, the Compensation Committee of our Board of Directors terminated the former SERP effective October 31, 2008 and replaced the supplemental retirement benefit with a non-qualified defined contribution restoration plan (DCR plan), effective January 1, 2009. Benefits payable under the new plan are informally funded through a rabbi trust with a bank as the trustee. We credit 13% of the total cash compensation (base salary, short-term incentive and MVP incentive) that exceeds the Internal Revenue Service compensation limit to the DCR plan account of each executive. An additional one-time credit was made for all eligible officers in January 2009 equal to the greater of:

- 13% of base salary paid in November 2008 and December 2008 (to the extent that calendar year-to-date base salary exceeded the 2008 annual limit), or
- Two monthly premiums (without adjustment for taxes) under the former SERP.

In addition, an opening balance that totaled $.3 million was established for four Vice Presidents to compensate them for the loss of future benefits under the new plan. Participants may not contribute to the DCR plan. Vesting under the DCR plan is five-year cliff vesting, including service prior to adoption, of annual company contributions, and prospective five-year cliff vesting for the opening balances of the four Vice Presidents. If the officer severs employment before the expiration of the relevant five-year period, he or she receives nothing from that portion of the DCR plan. Participants in the DCR plan may provide instructions to us for the deemed investment of their plan accounts. Distribution will occur upon separation of service or death of the participant. The insurance portion of the SERP benefit has been maintained in the form of new term life insurance as discussed below.

Also on September 4, 2008, the Compensation Committee of our Board of Directors approved a voluntary deferred compensation plan, effective January 1, 2009, for the benefit of all officers, director-level employees and regional executives. Benefits under this plan, known as the Voluntary Deferral Plan, are also informally funded through a rabbi trust with a bank as the trustee. There are no company contributions to the Voluntary Deferral Plan. Participants may defer up to 50% of base salary with elections made by December 31 prior to the upcoming calendar year, and up to 95% of annual incentive pay with elections made by April 30. Vesting is immediate and deferrals are held in the rabbi trust. Participants may provide instructions to us for the deemed investment of their plan accounts. Distributions can be made from the Voluntary Deferral Plan on a specified date that is at least two years from the date of deferral, on separation of service or upon death.

During the year ended October 31, 2009, we credited $.4 million to the DCR plan accounts. At October 31, 2009, we have a liability of $.7 million for these two deferred compensation plans.

We provide term life insurance policies for officers at the vice president level and above who were participants in the former SERP that terminated on October 31, 2008; the level of the insurance benefit is dependent upon the position of the officer. These life insurance policies are owned exclusively by each officer. Premiums on these policies are paid and expensed, as grossed up for taxes to the individual officer. Beginning on December 1, 2008, we provide a term life insurance benefit equal to $200,000 to all officers, director-level employees and regional executives for which we bear the cost of the policies. The cost of these premiums is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Vice president and above term life policies | $ 59 | $ - | $ - |
| SERP premiums (benefit superseded) | - | 446 | 455 |
| Officers, director-level employees and regional executives | 20 | - | - |

A reconciliation of changes in the plans' benefit obligations and fair value of assets for the years ended October 31, 2009 and 2008, and a statement of the funded status and the amounts reflected in the consolidated balance sheets for the years ended October 31, 2009 and 2008 are presented below.

| In thousands | Qualified Pension 2009 | Qualified Pension 2008 | Nonqualified Pension 2009 | Nonqualified Pension 2008 | Other Benefits 2009 | Other Benefits 2008 |
|---|---|---|---|---|---|---|
| Accumulated benefit obligation at year end | $ 173,352 | $ 135,516 | $ 4,828 | $ 4,194 | N/A | N/A |
| Change in benefit obligation: | | | | | | |
| Obligation at beginning of year | $ 143,460 | $ 188,698 | $ 4,194 | $ 4,845 | $ 28,112 | $ 33,612 |
| Service cost | 5,733 | 7,634 | 25 | 27 | 885 | 1,250 |
| Interest cost | 11,240 | 11,408 | 325 | 277 | 2,267 | 2,011 |
| Plan amendments | - | (4,133) | - | 127 | - | - |
| Actuarial (gain) loss | 45,436 | (43,208) | 920 | (532) | 7,506 | (5,895) |
| Settlement gain | - | - | (126) | - | - | - |
| Benefit payments | (10,540) | (16,939) | (510) | (550) | (3,247) | (2,866) |
| Obligation at end of year | $ 195,329 | $ 143,460 | $ 4,828 | $ 4,194 | $ 35,523 | $ 28,112 |
| Change in fair value of plan assets: | | | | | | |
| Fair value at beginning of year | $ 150,257 | $ 224,954 | $ - | $ - | $ 15,522 | $ 20,435 |
| Actual return on plan assets | 22,793 | (68,351) | - | - | 2,146 | (5,671) |
| Employer contributions | 22,000 | 11,000 | 510 | 550 | 4,857 | 3,624 |
| Administrative expenses | (233) | (407) | - | - | - | - |
| Benefit payments | (10,540) | (16,939) | (510) | (550) | (3,247) | (2,866) |
| Fair value at end of year | $ 184,277 | $ 150,257 | $ - | $ - | $ 19,278 | $ 15,522 |
| Noncurrent assets | $ - | $ 6,797 | $ - | $ - | $ - | $ - |
| Current liabilities | - | - | (484) | (528) | - | - |
| Noncurrent liabilities | (11,052) | - | (4,344) | (3,666) | (16,245) | (12,591) |
| Net amount recognized | $ (11,052) | $ 6,797 | $ (4,828) | $ (4,194) | $ (16,245) | $ (12,591) |
| Amounts Not Yet Recognized as a Component of Cost and Recognized as Regulatory Asset or Liability (1): | | | | | | |
| Unrecognized transition obligation | $ - | $ - | $ - | $ - | $ (2,668) | $ (3,335) |
| Unrecognized prior service (cost) credit | 26,033 | 28,231 | (107) | (127) | - | - |
| Unrecognized actuarial gain (loss) | (94,247) | (54,616) | (442) | 498 | (5,474) | 989 |
| Regulatory (asset) liability | (68,214) | (26,385) | (549) | 371 (2) | (8,142) | (2,346) |
| Cumulative employer contribution in excess of cost | 57,162 | 33,182 | (4,279) | (4,565) | (8,103) | (10,245) |
| Net amount recognized | $ (11,052) | $ 6,797 | $ (4,828) | $ (4,194) | $ (16,245) | $ (12,591) |

(1) As the future recovery of pension and OPEB costs is probable, we were granted permission to record the amount that would have been recorded in accumulated OCI as a regulatory asset or liability.

(2) Amount is composed of a regulatory asset of $2 and a regulatory liability of $373.

Net periodic benefit cost for the years ended October 31, 2009, 2008 and 2007 includes the following components.

| In thousands | Qualified Pension 2009 | Qualified Pension 2008 | Qualified Pension 2007 | Nonqualified Pension 2009 | Nonqualified Pension 2008 | Nonqualified Pension 2007 | Other Benefits 2009 | Other Benefits 2008 | Other Benefits 2007 |
|---|---|---|---|---|---|---|---|---|---|
| Service cost | $ 5,733 | $ 7,634 | $ 11,142 | $ 25 | $ 27 | $ 60 | $ 885 | $ 1,250 | $ 1,324 |
| Interest cost | 11,240 | 11,408 | 12,926 | 325 | 277 | 276 | 2,267 | 2,011 | 1,886 |
| Expected return on plan assets | (16,755) | (16,895) | (17,013) | - | - | - | (1,104) | (1,461) | (1,273) |
| Amortization of transition obligation | - | - | - | - | - | - | 667 | 667 | 667 |
| Amortization of prior service cost | (2,198) | (1,893) | 590 | 20 | - | - | - | - | - |
| Amortization of actuarial loss (gain) | - | - | 1,027 | (20) | - | - | - | - | - |
| Net periodic benefit (income) cost | (1,980) | 254 | 8,672 | 350 | 304 | 336 | 2,715 | 2,467 | 2,604 |
| Other changes in plan assets and benefit obligation recognized through regulatory asset or liability: | | | | | | | | | |
| Prior service cost (credit) | - | (4,133) | N/A | - | 127 | N/A | - | - | N/A |
| Net loss (gain) | 39,631 | 42,446 | N/A | 923 | (532) | N/A | 6,464 | 1,237 | N/A |
| Amounts recognized as a component of net periodic benefit cost: | | | | | | | | | |
| Transition obligation | - | - | N/A | - | - | N/A | (667) | (667) | N/A |
| Amortization of net gain | - | - | N/A | 20 | - | N/A | - | - | N/A |
| Prior service (cost) credit | 2,198 | 1,893 | N/A | (20) | - | N/A | - | - | N/A |
| Total recognized in regulatory asset (liability) | 41,829 | 40,206 | - | 923 | (405) | - | 5,797 | 570 | - |
| Total recognized in net periodic benefit cost and regulatory asset (liability) | $ 39,849 | $ 40,460 | $ 8,672 | $ 1,273 | $ (101) | $ 336 | $ 8,512 | $ 3,037 | $ 2,604 |

The 2010 estimated amortization of the following items is recorded as a regulatory asset or liability instead of accumulated OCI discussed above and expected refunds for our plans are as follows.

| In thousands | Qualified Pension | Nonqualified Pension | Other Benefits |
|---|---|---|---|
| Amortization of transition obligation | $ - | $ - | $ 667 |
| Amortization of unrecognized prior service (cost) credit | (2,198) | 20 | - |
| Amortization of unrecognized actuarial loss | 2,229 | 9 | 236 |
| Refunds expected | 31 | 29 | 903 |

In addition, equity market performance has a significant effect on our market-related value of plan assets. In determining the market-related value of plan assets, we use the following methodology: The asset gain or loss is determined each year by comparing the fund's actual return to the expected return, based on the disclosed expected return on investment assumption. Such asset gain or loss is then recognized ratably over a five-year period. Thus, the market-related value of assets as of year end is determined by adjusting the market value of assets by the portion of the prior five years' gains or losses that has not yet been recognized. This method has been applied consistently in all years presented in the consolidated financial statements. The discount rate can vary from plan year to plan year. October 31 is the measurement date for the plans.

The discount rate has been separately determined for each plan by projecting the plan's cash flows and developing a zero-coupon spot rate yield curve using non-arbitrage pricing and Moody's Investors Service's AA or better-rated non-callable bonds that produces similar results to a hypothetical bond portfolio. As of October 31, 2009, the benchmark by plan was as follows.

| | |
|---|---|
| Pension plan | 5.99% |
| NCNG SERP | 5.22% |
| Directors' SERP | 5.52% |
| Piedmont SERP | 4.58% |
| OPEB | 5.58% |

We amortize unrecognized prior-service cost over the average remaining service period for active employees. We amortize the unrecognized transition obligation over the average remaining service period for active employees expected to receive benefits under the plan as of the date of transition. We amortize gains and losses in excess of 10% of the greater of the benefit obligation and the market-related value of assets over the average remaining service period for active employees. The method of amortization in all cases is straight-line.

The weighted average assumptions used in the measurement of the benefit obligation as of October 31, 2009 and 2008 are presented below.

| | Qualified Pension | | Nonqualified Pension | | Other Benefits | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 |
| Discount rate | 5.99% | 8.15% | 5.28% | 8.46% | 5.58% | 8.50% |
| Rate of compensation increase | 3.92% | 3.97% | N/A | N/A | N/A | N/A |

The weighted average assumptions used to determine the net periodic benefit cost as of October 31, 2009, 2008 and 2007 are presented below.

| | Qualified Pension | | | Nonqualified Pension | | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2007 | 2009 | 2008 | 2007 |
| Discount rate | 8.15% | 6.43% | 5.78% | 8.46% | 6.06% | 5.67% |
| Expected long-term rate of return on plan assets | 8.00% | 8.00% | 8.50% | N/A | N/A | N/A |
| Rate of compensation increase | 3.97% | 3.99% | 4.01% | N/A | N/A | N/A |

| | Other Benefits | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Discount rate | 8.50% | 6.25% | 5.74% |
| Expected long-term rate of return on plan assets | 8.00% | 8.00% | 8.50% |
| Rate of compensation increase | N/A | N/A | N/A |

The weighted average asset allocations by asset category for the pension plan and the OPEB plan as of October 31, 2009 and 2008 and the current asset category targets are presented below.

| | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | Current Target | 2009 | 2008 | Current Target |
| Domestic equity securities | 35% | 43% | 35% | 29% | 35% | 31% |
| International equity securities | 15% | 8% | 17% | 19% | 23% | 18% |
| Fixed income securities | 39% | 44% | 48% | 27% | 37% | 51% |
| Cash | 11% | 5% | - % | 25% | 5% | - % |
| Total | 100% | 100% | 100% | 100% | 100% | 100% |

Our primary investment objective is to generate sufficient assets to meet plan liabilities. The plans' assets will therefore be invested to maximize long-term returns consistent with the plans' liabilities, cash flow requirements and risk tolerance. We consider the historical long-term return experience of our assets, the current and targeted allocation of our plan assets and the expected long-term rates of return. Investment advisors assist us in deriving expected long-term rates of return. These rates are generally based on a 20-year horizon for various asset classes, our expected investments of plan assets and active asset management instead of a passive investment strategy of an index fund. In June 2009, the Benefits Committee of the Board of Directors approved a new asset allocation of our portfolio that includes additional asset classes, such as hedge fund of funds, private equity fund of funds, high yield bonds, global real estate and commodities. The intent of this new allocation was to provide further diversification and reduce volatility of plan assets. These new asset allocation categories are included within the broad asset categories in the above table. The process of implementing the new asset allocation resulted in a higher-than-normal cash allocation as of October 31, 2009. The plans' liabilities are primarily defined in terms of participant salaries. Given the nature of these liabilities, and recognizing the long-term benefits of investing in both domestic and international equity securities, we invest in a diversified portfolio which includes a significant exposure to these investments. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies. We intend to use 8% as the expected long-term rate of return on the pension and OPEB plans for 2010. The 8% expected long-term rate of return on the plan assets is based on our target allocation for the trust where we are in the process of re-allocating the assets to the target objective.

Specific financial targets include:

- Achieve full funding over the longer term for our defined benefit pension plan,
- Control fluctuation in pension expense from year to year,
- Achieve satisfactory performance relative to other similar pension plans, and
- Achieve positive returns in excess of inflation over short to intermediate time frames.

We anticipate that we will contribute the following amounts to our plans in 2010.

| In thousands | |
|---|---|
| Qualified pension plan | $ 22,000 |
| Nonqualified pension plans | 484 |
| MPP plan | 220 |
| OPEB plan | 2,700 |

The Pension Protection Act of 2006 (PPA) contains new funding requirements for single employer defined benefit pension plans. The PPA establishes a 100% funding target for plan years beginning after December 31, 2007. We contributed more than was required for our qualified plan in 2009.

Benefit payments, which reflect expected future service, as appropriate, are expected to be paid for the next ten years ending October 31 as follows.

| In thousands | Qualified Pension | Nonqualified Pension | Other Benefits |
|---|---|---|---|
| 2010 | $ 17,259 | $ 484 | $ 2,743 |
| 2011 | 12,103 | 486 | 2,695 |
| 2012 | 11,232 | 471 | 2,688 |
| 2013 | 12,992 | 468 | 2,743 |
| 2014 | 12,960 | 438 | 2,998 |
| 2015 - 2019 | 78,163 | 1,932 | 16,601 |

The assumed health care cost trend rates used in measuring the accumulated OPEB obligation for the medical plans for all participants as of October 31, 2009 and 2008 are presented below.

| | 2009 | 2008 |
|---|---|---|
| Health care cost trend rate assumed for next year | 8.00% | 8.25% |
| Rate to which the cost trend is assumed to decline (the ultimate trend rate) | 5.00% | 5.00% |
| Year that the rate reaches the ultimate trend rate | 2027 | 2017 |

The health care cost trend rate assumptions could have a significant effect on the amounts reported. A change of 1% would have the following effects.

| In thousands | 1% Increase | 1% Decrease |
|---|---|---|
| Effect on total of service and interest cost components of net periodic postretirement health care benefit cost for the year ended October 31, 2009 | $ 63 | $ (64) |
| Effect on the health care cost component of the accumulated postretirement benefit obligation as of October 31, 2009 | 1,005 | (941) |

We maintain 401(k) plans which are profit-sharing plans under Section 401(a) of the Internal Revenue Code of 1986, as amended (the Tax Code), which include qualified cash or deferred arrangements under Tax Code Section 401(k). The 401(k) plans are subject to the provisions of the Employee Retirement Income Security Act. Eligible employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Participants may defer a portion of their base salary and cash incentive payments to the plans, and we match a portion of their contributions. Employee contributions vest immediately, and company contributions vest after six months of service.

Effective January 1, 2008, we made changes to our 401(k) plans. Prior to January 1, 2008, we matched 50% of employee contributions up to the first 10% of pay contributed. Beginning January 1, 2008 (January 1, 2009 for employees covered under the bargaining unit contract in Nashville, Tennessee), employees receive a company match of 100% up to the first 5% of eligible pay contributed. Employees may contribute up to 50% of eligible pay to the 401(k) on a pre-tax basis, up to the Tax Code annual contribution limit. We automatically enroll all affected non-participating employees in the 401(k) plan as of January 1, 2008 (January 1, 2009 for employees covered under the bargaining unit contract in Nashville, Tennessee) at a 2% contribution rate unless the employee chooses not to participate by notifying our record keeper. For employees who are automatically enrolled in the 401(k) plan, we automatically increase their contributions by 1% each year to a maximum of 5% unless the employee chooses to opt out of the automatic increase by contacting our record keeper. If the employee does not make an investment election, employee contributions and matches are automatically invested in a diversified portfolio of stocks and bonds. Participants may invest in Piedmont stock up to a maximum of 20% of their account. Employees may change their contribution rate and investments at any time. For the years ended October 31, 2009, 2008 and 2007, we made matching contributions to participant accounts as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| 401(k) matching contributions | $ 4,698 | $ 4,252 | $ 3,191 |

As a result of a plan merger effective in 2001, participants' accounts in our employee stock ownership plan (ESOP) were transferred into our 401(k) plans. Former ESOP participants may remain invested in Piedmont common stock in their 401(k) plan or may sell the common stock at any time and reinvest the proceeds in other available investment options. The tax benefit of any dividends paid on ESOP shares still in participants' accounts is reflected in the consolidated statement of stockholders' equity as an increase in retained earnings.

9. Employee Share-Based Plans

Under Board of Directors approved incentive compensation plans, eligible officers and other participants are awarded units that pay out depending upon the level of performance achieved by Piedmont during three-year performance periods. Distribution of those awards may be made in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation. These plans require that a minimum threshold performance level be achieved in order for any award to be distributed. For the years ended October 31, 2009, 2008 and 2007, we recorded compensation expense, and as of October 31, 2009 and 2008, we have accrued amounts for these awards based on the fair market value of our stock at the end of each quarter. The liability is re-measured to market value at the settlement date.

We have three awards under approved incentive compensation plans with three-year performance periods ending October 31, 2009, October 31, 2010 and October 31, 2011. Fifty percent of the units awarded will be based on achievement of a target annual compounded increase in basic EPS. For this 50% portion, an EPS performance of 80% of target will result in an 80% payout, an EPS performance of 100% of target will result in a 100% payout and an EPS performance of 120% of target will result in a maximum 120% payout, and EPS performance levels between these levels will be subject to mathematical interpolation. EPS performance below 80% of target will result in no payout of this portion. The other 50% of the units awarded will be based on the achievement of total annual shareholder return (increase in our common stock price plus dividends reinvested over the specified period of time) in comparison to a peer group consisting of natural gas distribution companies. The total shareholder return performance measure will be our percentile ranking in relationship to the peer group. For this 50% portion, a ranking below the 25th percentile will result in no payout, a ranking between the 25th and 39th percentile will result in an 80% payout, a ranking between the 40th and 49th percentile will result in a 90% payout, a ranking between the 50th and 74th percentile will result in a 100% payout, a ranking between the 75th and 89th percentile will result in a 110% payout, and a ranking at or above the 90th percentile will result in a maximum 120% payout.

We had one additional award with a five-year performance period that ended October 31, 2006, for a group of retired employees with 75% of the units awarded being based on achievement of a target cumulative increase in net income and 25% of the units awarded based on achievement of a target total annual shareholder return in comparison to the A. G. Edwards Large Natural Gas Distribution Index industry peer group and in the same percentile rankings. The payout under this award occurred over a three-year period. The third and final payout occurred in fiscal 2009.

Also under our approved incentive compensation plan, 65,000 unvested shares of our common stock with a value at the date of grant of $1.7 million were granted to our President and Chief Executive Officer in September 2006. During the five-year vesting period, any dividends paid on these shares are accrued and converted into additional shares at the closing price on the date of the dividend payment. The unvested shares and any additional shares accrued through dividends will vest over a five-year period only if he is an employee on each vesting date. In accordance with the vesting schedule, 20% of the shares vested on September 1, 2009. The remaining 30% and 50% of the shares will vest on September 1, 2010 and 2011, respectively.

Through August 2009, we recorded compensation for the unvested shares on the straight-line method. In September 2009, the Compensation Committee of the Board of Directors clarified the tax withholding provisions of the award. This clarification required us to correct our accounting for the award from an equity award to a liability award. There was no material impact on our financial position, results of operations or cash flows from September 1, 2006 through August 31, 2009. Subsequent to August 2009, we recorded compensation expense in accordance with the vesting schedule, and the liability related to this award is re-measured to market value at the end of each reporting quarter period and at the settlement dates.

The award which vested as of September 1, 2009 covered 20% of the grant, including accrued dividends, for a total of 14,611 shares of common stock. After the withholding of $.2 million for federal and state taxes, our President and Chief Executive Officer received 8,153 shares of common stock valued at the New York Stock Exchange composite closing price at September 1, 2009 of $24.24.

The compensation expense related to the incentive compensation plans for the years ended October 31, 2009, 2008 and 2007, and the amounts recorded as liabilities as of October 31, 2009 and 2008 are presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Compensation expense | $ 2,487 | $ 7,027 | $ 2,002 |
| Tax benefit | 207 | 1,555 | 786 |
| Liability | 8,173 | 10,749 | |

Based on current accrual assumptions, the expected payout for the approved incentive compensation plans ending October 31, 2009, 2010 and 2011 will occur in the following fiscal years.

| In thousands | 2010 | 2011 | 2012 |
|---|---|---|---|
| Amount of payout | $ 3,705 | $ 3,252 | $ 1,216 |

On a quarterly basis, we issue shares of common stock under the ESPP and have accounted for the issuance as an equity transaction. The exercise price is calculated as 95% of the fair market value on the purchase date of each quarter where fair market value is determined by calculating the mean average of the high and low trading prices on the purchase date.

As discussed in Note 5, we repurchase shares on the open market and such shares are then cancelled and become authorized but unissued shares. Currently, it is our policy to issue new shares for share-based awards. Shares of common stock to be issued under approved incentive compensation plans are contingently issuable shares and are included in our calculation of fully diluted earnings per share.

10. Income Taxes

The components of income tax expense for the years ended October 31, 2009, 2008 and 2007 are presented below.

| In thousands | 2009 Federal | 2009 State | 2008 Federal | 2008 State | 2007 Federal | 2007 State |
|---|---|---|---|---|---|---|
| Charged to operating income: | | | | | | |
| Current | $ (7,774) | $ 181 | $ 27,971 | $ 6,679 | $ 28,233 | $ 4,987 |
| Deferred | 65,828 | 12,047 | 24,285 | 4,237 | 15,250 | 3,279 |
| Tax Credits | | | | | | |
| Utilization | 130 | - | - | - | - | - |
| Amortization | (333) | - | (358) | - | (434) | - |
| Total | 57,851 | 12,228 | 51,898 | 10,916 | 43,049 | 8,266 |
| Charged to other income (expense): | | | | | | |
| Current | 7,764 | 1,064 | 10,040 | 1,786 | 7,557 | 1,153 |
| Deferred | 2,492 | 483 | (1,025) | (123) | 4,644 | 957 |
| Total | 10,256 | 1,547 | 9,015 | 1,663 | 12,201 | 2,110 |
| Total | $ 68,107 | $ 13,775 | $ 60,913 | $ 12,579 | $ 55,250 | $ 10,376 |

A reconciliation of income tax expense at the federal statutory rate to recorded income tax expense for the years ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Federal taxes at 35% | $ 71,647 | $ 64,225 | $ 59,504 |
| State income taxes, net of federal benefit | 8,954 | 8,176 | 6,745 |
| Amortization of investment tax credits | (333) | (358) | (434) |
| Other, net | 1,614 | 1,449 | (189) |
| Total | $ 81,882 | $ 73,492 | $ 65,626 |

As of October 31, 2009 and 2008, deferred income taxes consisted of the following temporary differences.

| In thousands | 2009 | 2008 |
|---|---|---|
| Deferred tax assets | | |
| Benefit of loss carryforwards | $ 17,995 | $ 2,564 |
| Employee benefits and compensation | 17,233 | 11,661 |
| Utility plant | 9,197 | 3,212 |
| Other | 15,528 | 16,486 |
| Total deferred tax assets | 59,953 | 33,923 |
| Valuation Allowance | (1,400) | (1,114) |
| Total deferred tax assets, net | 58,553 | 32,809 |
| Deferred tax liabilities | | |
| Utility plant | 334,878 | 274,272 |
| Revenues and cost of gas | 40,043 | 19,907 |
| Equity method investments | 22,597 | 19,501 |
| Deferred costs | 49,279 | 25,980 |
| Other | 3,456 | 5,389 |
| Total deferred tax liabilities | 450,253 | 345,049 |
| Net deferred income tax liabilities | $ 391,700 | $ 312,240 |

As of October 31, 2009 and 2008, total net deferred income tax assets were net of a valuation allowance to reduce amounts to the amounts that we believe will be more likely than not realized. We and our wholly owned subsidiaries file a consolidated federal income tax return and various state income tax returns. As of October 31, 2009 and 2008, we had federal net operating loss carryforwards of $45.6 million and $6.6 million, respectively, that expire from 2025 through 2029. As of October 31, 2009 and 2008, we had state net operating loss carryforwards of $58.2 million and $6.6 million, respectively, that expire from 2019 through 2024. We may use the loss carryforwards to offset taxable income. $6.5 million of the loss carryforwards are subject to an annual limitation of $.3 million.

During the year ended October 31, 2007, the Internal Revenue Service finalized its audit of our returns for the tax years ended October 31, 2003 through 2005. The audit results, which did not have a material effect on our financial position or results of operations, have been reflected in the consolidated financial statements. We are no longer subject to federal income tax examinations for tax years ending before and including October 31, 2005, and with few exceptions, state income tax examinations by tax authorities for years ended before and including October 31, 2003.

A reconciliation of changes in the deferred tax valuation allowance for the years ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Balance at beginning of year | $ 1,114 | $ 394 | $ 568 |
| Charged (credited) to income tax expense | 286 | 720 | (174) |
| Balance at end of year | $ 1,400 | $ 1,114 | $ 394 |

We adopted the accounting regulations related to uncertain income tax obligations on November 1, 2007. As a result of the implementation of the uncertain income tax obligations regulations, there was no material impact on the consolidated financial statements, and no adjustment to retained earnings. The amount of unrecognized tax benefits at November 1, 2007 was $.5 million, of which $.3 million would impact our effective income tax rate if recognized.

A reconciliation of the unrecognized tax benefits for the years ended October 31, 2009 and 2008 is presented below.

| In thousands | 2009 | 2008 |
|---|---|---|
| Balance, beginning of year | $ 506 | $ 474 |
| Increase from prior year's tax positions | - | 72 |
| Decrease from settlements with taxing authorities | 125 | 40 |
| Decrease from expiration of statute of limitations | 88 | - |
| Balance, end of year | $ 293 | $ 506 |

The amount of unrecognized tax benefits at October 31, 2009 and 2008 which would impact our effective income tax rate if recognized was $.2 million and $.3 million, respectively.

We recognize accrued interest and penalties related to unrecognized tax benefits in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. We recorded $.03 million and $.1 million of interest related to unrecognized tax benefits during the years ended October 31, 2009 and 2008, respectively.

For state tax purposes, we have unrecognized tax benefits related to the treatment of sales of certain assets that we anticipate will decrease by $.3 million due to a settlement with taxing authorities or the expiration of the statute of limitations within the next twelve months.

11. Equity Method Investments

The consolidated financial statements include the accounts of wholly owned subsidiaries whose investments in joint venture, energy-related businesses are accounted for under the equity method. Our ownership interest in each entity is included in "Equity method investments in non-utility activities" in the consolidated balance sheets. Earnings or losses from equity method investments are included in "Income from equity method investments" in the consolidated statements of income.

As of October 31, 2009, there were no amounts that represented undistributed earnings of our 50% or less owned equity method investments in our retained earnings.

Cardinal Pipeline Company, L.L.C.

We own 21.49% of the membership interests in Cardinal Pipeline Company, L.L.C., a North Carolina limited liability company. The other members are subsidiaries of The Williams Companies, Inc., and SCANA Corporation. Cardinal owns and operates an intrastate natural gas pipeline in North Carolina and is regulated by the NCUC. Cardinal has firm service agreements with local distribution companies for 100% of the firm transportation capacity on the pipeline, of which Piedmont subscribes to approximately 37%. Cardinal is dependent on the Williams-Transco pipeline system to deliver gas into its system for service to its customers. Cardinal's long-term debt is secured by Cardinal's assets and by each member's equity investment in Cardinal.

On October 22, 2009, we reached an agreement with Progress Energy Carolinas, Inc. to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. To provide the additional delivery service, we have executed an agreement with Cardinal, which is subject to NCUC approval, to expand our firm capacity requirement by 149,000 dekatherms per day to serve Progress Energy Carolinas. This will require Cardinal to spend as much as $39.2 million to expand its system with the addition of a new compressor station and expanded meter stations in order to increase the capacity of its system by up to 199,000 dekatherms per day of firm capacity. As an equity venture partner of Cardinal, we will invest as much as $8.7 million in Cardinal's system expansion. When the project is placed into service on the scheduled in service date of July 1, 2012, the members' capital will be replaced with permanent financing with a target overall capital structure of 45-50% debt and 50-55% equity. The NCUC issued a formal certificate order for the Progress Energy Carolinas Wayne County generation project on October 1, 2009.

We have related party transactions as a transportation customer of Cardinal, and we record in cost of gas the transportation costs charged by Cardinal. For each of the years ended October 31, 2009, 2008 and 2007, these transportation costs and the amounts we owed Cardinal as of

October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Transportation costs | $ 4,104 | $ 4,116 | $ 4,549 |
| Trade accounts payable | 349 | 349 | |

Summarized financial information provided to us by Cardinal for 100% of Cardinal as of September 30, 2009 and 2008, and for the twelve months ended September 30, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Current assets | $ 9,078 | $ 10,010 | |
| Non-current assets | 78,089 | 80,851 | |
| Current liabilities | 3,990 | 5,229 | |
| Non-current liabilities | 29,075 | 31,439 | |
| Revenues | 13,633 | 13,670 | $ 15,369 |
| Gross profit | 13,633 | 13,670 | 15,369 |
| Income before income taxes | 6,893 | 7,050 | 8,371 |

Pine Needle LNG Company, L.L.C.

We own 40% of the membership interests in Pine Needle LNG Company, L.L.C., a North Carolina limited liability company. The other members are the Municipal Gas Authority of Georgia and subsidiaries of The Williams Companies, Inc., SCANA Corporation and Hess Corporation. Pine Needle owns an interstate LNG storage facility in North Carolina and is regulated by the FERC. Pine Needle has firm service agreements for 100% of the storage capacity of the facility, of which Piedmont subscribes to approximately 64%.

Pine Needle enters into interest-rate swap agreements to modify the interest characteristics of its long-term debt. Our share of movements in the market value of these agreements are recorded as a hedge in "Accumulated other comprehensive income" in the consolidated balance sheets. Pine Needle's long-term debt is secured by Pine Needle's assets and by each member's equity investment in Pine Needle.

We have related party transactions as a customer of Pine Needle, and we record in cost of gas the storage costs charged by Pine Needle. For the years ended October 31, 2009, 2008 and 2007, these gas storage costs and the amounts we owed Pine Needle as of October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Gas storage costs | $ 12,364 | $ 11,516 | $ 11,727 |
| Trade accounts payable | 1,081 | 1,019 | |

Summarized financial information provided to us by Pine Needle for 100% of Pine Needle as of September 30, 2009 and 2008, and for the twelve months ended September 30, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Current assets | $ 10,618 | $ 12,618 | |
| Non-current assets | 78,452 | 81,934 | |
| Current liabilities | 8,485 | 10,846 | |
| Non-current liabilities | 20,526 | 25,175 | |
| Revenues | 18,744 | 18,694 | $ 18,668 |
| Gross profit | 18,744 | 18,694 | 18,668 |
| Income before income taxes | 8,381 | 8,227 | 8,827 |

SouthStar Energy Services LLC

We own 30% of the membership interests in SouthStar Energy Services LLC, a Delaware limited liability company. Under the terms of the Amended and Restated Limited Liability Company Agreement (Restated Agreement), earnings and losses are allocated 25% to us and 75% to the other member, GNGC, a subsidiary of AGLR, with the exception of earnings and losses in the Ohio and Florida markets, which are allocated to us at our ownership percentage of 30%. SouthStar primarily sells natural gas to residential, commercial and industrial customers in the southeastern United States with most of its business being conducted in the unregulated retail gas market in Georgia.

The SouthStar Restated Agreement included a provision granting GNGC the option to purchase our ownership interest in SouthStar, which we believed expired on November 1, 2009. On July 29, 2009, we restructured the ownership interests in SouthStar. Under the terms of the new agreement, we will sell half of our 30% membership interest in SouthStar to GNGC effective January 1, 2010, retaining a 15% earnings and membership share in SouthStar after the sale. At closing, we will receive $57.5 million from GNGC resulting in an estimated after-tax gain of $30 million in 2010 or $.42 per diluted share. As part of the agreement, GNGC will not have any further option rights to our remaining 15% interest. The agreement has been approved by both companies' boards of directors, and on October 6, 2009, was approved by the Georgia PSC. For further information, see Note 7 to the consolidated financial statements.

SouthStar's business is seasonal in nature as variations in weather conditions generally result in greater revenue and earnings during the winter months when weather is colder and natural gas consumption is higher. Also, because SouthStar is not a rate-regulated company, the timing of its earnings can be affected by changes in the wholesale price of natural gas. While SouthStar uses financial contracts to moderate the effect of price and weather changes on the timing of its earnings, wholesale price and weather volatility can cause variations in the timing of the recognition of earnings.

These financial contracts, in the form of futures, options and swaps, are considered to be derivatives and fair value is based on selected market indices. Our share of movements in the market value of these contracts are recorded as a hedge in "Accumulated other comprehensive income" in the consolidated balance sheets.

We have related party transactions as we sell wholesale gas supplies to SouthStar, and we record in operating revenues the amounts billed to SouthStar. For the years ended October 31, 2009, 2008 and 2007, our operating revenues from these sales and the amounts SouthStar owed us as of October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Operating revenues | $ 8,226 | $ 14,624 | $ 8,866 |
| Trade accounts receivable | 639 | 1,202 | |

Summarized financial information provided to us by SouthStar for 100% of SouthStar as of September 30, 2009 and 2008, and for the twelve months ended September 30, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Current assets | $ 148,402 | $ 238,662 | |
| Non-current assets | 9,454 | 13,463 | |
| Current liabilities | 50,010 | 144,552 | |
| Non-current liabilities | - | 338 | |
| Revenues | 854,455 | 941,123 | $ 908,416 |
| Gross profit | 169,639 | 143,534 | 177,822 |
| Income before income taxes | 98,308 | 73,224 | 112,260 |

Hardy Storage Company, LLC

Piedmont Hardy Storage Company, LLC (Piedmont Hardy), a wholly owned subsidiary of Piedmont, owns 50% of the membership interests in Hardy Storage Company, LLC (Hardy Storage), a West Virginia limited liability company. The other owner is a subsidiary of Columbia Gas Transmission Corporation, a subsidiary of NiSource Inc. Hardy Storage owns and operates an underground interstate natural gas storage facility located in Hardy and Hampshire Counties, West Virginia, that is regulated by the FERC. Initial service to customers began April 1, 2007 when customers began injecting gas into storage for subsequent winter withdrawals. Final service levels were placed into service on April 1, 2009 as scheduled. Hardy Storage has firm service contracts for 100% of its storage capacity of the facility, of which Piedmont subscribes to approximately 40%.

On June 29, 2006, Hardy Storage signed a note purchase agreement for interim notes and a revolving equity bridge facility for up to a total of $173.1 million for funding during the construction period. On November 1, 2007, Hardy Storage paid off the equity line of $10.2 million with member equity contributions, leaving an amount outstanding on the interim notes of $123.4 million.

The members of Hardy Storage have each agreed to guarantee 50% of the construction financing. Our guaranty was executed by Piedmont Energy Partners, Inc. (PEP), a wholly owned subsidiary of Piedmont and a sister company of Piedmont Hardy. Our share of the guaranty is capped at $111.5 million. Depending upon the facility's performance over the first three years after the in-service date, there could be additional construction expenditures of up to $10 million for contingency wells, of which PEP will guarantee 50%.

Securing PEP's guaranty is a pledge of intercompany notes issued by Piedmont held by non-utility subsidiaries of PEP. Should Hardy Storage be unable to perform its payment obligation under the construction financing, PEP will call on Piedmont for the payment of the notes, plus accrued interest, for the amount of the guaranty. Also pledged is our membership interest in Hardy Storage.

For 2009, we made equity contributions of $.9 million to fund construction expenditures, with our total equity contributions for the project totaling $24.7 million as of October 31, 2009. Upon completion of project construction, including any contingency wells if needed, the members intend to target a capitalization structure of 70% debt and 30% equity. After the satisfaction of certain conditions in the note purchase agreement, amounts outstanding under the interim notes will convert to a fifteen-year mortgage-style debt instrument without recourse to the members. We expect the conversion to occur in our first quarter 2010, but no later than May 2010. To the extent that more funding is needed, the members will evaluate funding options at that time.

We record a liability at fair value for this guaranty based on the present value of 50% of the construction financing outstanding at the end of each quarter, with a corresponding increase to our investment account in the venture. As our risk in the project changes, the fair value of the guaranty is adjusted accordingly through a quarterly evaluation. The details of the guaranty at October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 |
|---|---|---|
| Guaranty liability- PEP | $ 1,234 | $ 1,234 |
| Amount outstanding under the construction financing - Hardy Storage | 123,410 | 123,410 |

We have related party transactions as a customer of Hardy Storage and record in cost of gas the storage costs charged by Hardy Storage. For the years ended October 31, 2009, 2008 and 2007, these gas storage costs and the amounts we owed Hardy Storage as of October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Gas storage costs | $ 9,340 | $ 9,219 | $ 3,505 |
| Trade accounts payable | 781 | 774 | |

Summarized financial information provided to us by Hardy Storage for 100% of Hardy Storage as of October 31, 2009 and 2008, and for the twelve months ended October 31, 2009, 2008 and 2007 is presented below.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Current assets | $ 37,136 | $ 27,760 | |
| Non-current assets | 166,663 | 168,160 | |
| Current liabilities | 127,288 | 5,878 | |
| Non-current liabilities | - | 123,410 | |
| Revenues | 23,465 | 23,658 | $ 13,902 |
| Gross profit | 23,465 | 23,658 | 13,902 |
| Income before income taxes | 8,155 | 9,297 | 8,918 |

12. Business Segments

We have two reportable business segments, regulated utility and non-utility activities. These segments were identified based on products and services, regulatory environments and our current corporate organization and business decision-making activities. Operations of our regulated utility segment are conducted by the parent company. Operations of our non-utility activities segment are comprised of our equity method investments in joint ventures.

Operations of the regulated utility segment are reflected in operating income in the consolidated statements of income. Operations of the non-utility activities segment are included in the consolidated statements of income in "Income from equity method investments" and "Non-operating income."

We evaluate the performance of the regulated utility segment based on margin, operations and maintenance expenses and operating income. We evaluate the performance of the non-utility activities segment based on earnings from the ventures. All of our operations are within the United States. No single customer accounts for more than 10% of our consolidated revenues.

Operations by segment for the years ended October 31, 2009, 2008 and 2007, and as of October 31, 2009 and 2008 are presented below.

| In thousands | Regulated Utility | Non-Utility Activities | Total |
|---|---|---|---|
| 2009 | | | |
| Revenues from external customers | $ 1,638,116 | $ - | $ 1,638,116 |
| Margin | 561,574 | - | 561,574 |
| Operations and maintenance expenses | 208,105 | 326 | 208,431 |
| Depreciation | 97,425 | 29 | 97,454 |
| Income from equity method investments | - | 33,464 | 33,464 |
| Interest expense | 46,675 | 34 | 46,709 |
| Operating income (loss) before income taxes | 221,454 | (503) | 220,951 |
| Income before income taxes | 171,752 | 32,954 | 204,706 |
| Total assets | 2,919,260 | 104,891 | 3,024,151 |
| Equity method investments in non-utility activities | - | 104,429 | 104,429 |
| Construction expenditures | 129,006 | - | 129,006 |

| In thousands | Regulated Utility | Non-Utility Activities | Total |
|---|---|---|---|
| 2008 | | | |
| Revenues from external customers | $ 2,089,108 | $ - | $ 2,089,108 |
| Margin | 552,973 | - | 552,973 |
| Operations and maintenance expenses | 210,757 | 160 | 210,917 |
| Depreciation | 93,121 | 29 | 93,150 |
| Income from equity method investments | - | 27,718 | 27,718 |
| Interest expense | 59,273 | 79 | 59,352 |
| Operating income (loss) before income taxes | 215,925 | (277) | 215,648 |
| Income before income taxes | 156,400 | 27,099 | 183,499 |
| Total assets | 2,908,690 | 99,699 | 3,008,389 |
| Equity method investments in non-utility activities | - | 99,214 | 99,214 |
| Construction expenditures | 181,012 | - | 181,012 |

| In thousands | Regulated Utility | Non-Utility Activities | Total |
|---|---|---|---|
| 2007 | | | |
| Revenues from external customers | $ 1,711,292 | $ - | $ 1,711,292 |
| Margin | 524,165 | - | 524,165 |
| Operations and maintenance expenses | 214,442 | 325 | 214,767 |
| Depreciation | 88,654 | 29 | 88,683 |
| Income from equity method investments | - | 37,156 | 37,156 |
| Interest expense | 57,272 | - | 57,272 |
| Operating income (loss) before income taxes | 188,662 | (518) | 188,144 |
| Income before income taxes | 133,726 | 36,287 | 170,013 |
| Construction expenditures | 135,241 | - | 135,241 |

Reconciliations to the consolidated financial statements for the years ended October 31, 2009, 2008 and 2007, and as of October 31, 2009 and 2008 are as follows.

| In thousands | 2009 | 2008 | 2007 |
|---|---|---|---|
| Operating Income: | | | |
| Segment operating income before income taxes | $ 220,951 | $ 215,648 | $ 188,144 |
| Utility income taxes | (70,079) | (62,814) | (51,315) |
| Non-utility activities before income taxes | 503 | 277 | 518 |
| Total | $ 151,375 | $ 153,111 | $ 137,347 |
| Net Income: | | | |
| Income before income taxes for reportable segments | $ 204,706 | $ 183,499 | $ 170,013 |
| Income taxes | (81,882) | (73,492) | (65,626) |
| Total | $ 122,824 | $ 110,007 | $ 104,387 |
| Consolidated Assets: | | | |
| Total assets for reportable segments | $ 3,024,151 | $ 3,053,210 | |
| Eliminations/Adjustments | 94,668 | 85,191 | |
| Total | $ 3,118,819 | $ 3,138,401 | |

## 13. Restructuring and Other Termination Benefits

In 2007, we implemented organizational changes under our business process improvement program to streamline business processes, capture operational and organizational efficiencies and improve customer service. As a part of this effort, we initiated changes in our customer payment and collection processes, including no longer accepting customer payments in our business offices and streamlining our district operations. We also further consolidated our call centers. Collections of delinquent accounts were consolidated in our central business office. These specific initiatives were largely completed as of October 31, 2008.

We accrued costs in connection with these initiatives in the form of severance benefits to employees who were either voluntarily or involuntarily severed. These benefits were under existing arrangements and were accounted for in accordance with accounting regulations for employers' accounting for postemployment benefits. All costs were included in the regulated utility segment in "Operations and maintenance" expenses in the consolidated statements of income. For the years ended October 31, 2009, 2008 and 2007, we expensed benefits of ($.02) million, ($.3) million and $3.6 million, respectively.

A reconciliation of activity to the liability as of October 31, 2009 and 2008 is as follows.

| In thousands | 2009 | 2008 |
|---|---|---|
| Beginning liability | $ 22 | $ 1,459 |
| Costs paid | - | (1,132) |
| Adjustment to accruals | (22) | (305) |
| Ending liability | $ - | $ 22 |

14. Adjustment of Statement of Cash Flows and Balance Sheet for the Adoption of Amended Guidance for "Offsetting of Amounts Related to Certain Contracts"

In April 2007, the FASB amended guidance related to "Offsetting of Amounts Related to Certain Contracts." Prior to the effective date of the amended guidance, our policy was to present our positions, exclusive of any receivable or payable, with the same counterparty on a net basis. On November 1, 2008, we elected "not to net" fair value amounts for our derivative instruments or the fair value of the right to reclaim cash collateral in accordance with accounting guidance, and we moved to a gross presentation.

The following table reflects the adjustments on our consolidated balance sheets and consolidated statements of cash flows as a result of the change from the net to the gross method.

| In thousands | As Previously Reported | As Adjusted |
|---|---|---|
| As of October 31, 2008 | | |
| Total current assets | $ 600,752 | $ 623,396 |
| Total noncurrent assets | 251,130 | 273,307 |
| Total current liabilities | 681,533 | 704,177 |
| Total noncurrent liabilities | 730,542 | 752,719 |
| For the Twelve Months Ended October 31, 2008 | | |
| Cash Flows from Operating Activities: | | |
| Changes in asset and liabilities: | | |
| Gas purchase options, at fair value | $ - | $ 23,029 |
| Other assets | (5,469) | (8,936) |
| Other liabilities | 33,319 | 13,757 |
| For the Twelve Months Ended October 31, 2007 | | |
| Cash Flows from Operating Activities: | | |
| Changes in asset and liabilities: | | |
| Gas purchase options, at fair value | $ - | $ (10,578) |
| Other assets | (351) | 10,227 |

15. Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated through December 23, 2009, the filing date of this Form 10-K. For information on subsequent event disclosure items related to regulatory matters and common stock, see Note 2 and Note 5, respectively, to the consolidated financial statements.

On November 20, 2009, we filed a registration statement with the SEC to register the offering of 2.75 million shares of our common stock under our DRIP. This filing covers future sales of our common stock under the DRIP. As a result of an administrative error, between December 1, 2008 and November 16, 2009, we sold 568,000 shares of common stock under our DRIP that did not comply with the registration requirements of applicable securities laws. For additional information see Note 5 to the consolidated financial statements.

* * * * * *

Selected Quarterly Financial Data (In thousands except per share amounts) (Unaudited)

| | Operating Revenues | Margin | Operating Income | Net Income (Loss) | Earnings (Loss) Per Share of Common Stock Basic | Diluted |
|---|---|---|---|---|---|---|
| Fiscal Year 2009 | | | | | | |
| January 31 | $ 779,644 | $ 220,683 | $ 88,131 | $ 80,876 | $ 1.10 | $ 1.10 |
| April 30 | 455,432 | 169,953 | 55,351 | 53,525 | 0.73 | 0.73 |
| July 31 | 180,201 | 80,839 | 1,585 | (7,300) | (0.10) | (0.10) |
| October 31 | 222,839 | 90,099 | 6,308 | (4,277) | (0.06) | (0.06) |
| Fiscal Year 2008 | | | | | | |
| January 31 | $ 788,470 | $ 227,026 | $ 91,936 | $ 82,268 | $ 1.12 | $ 1.12 |
| April 30 | 634,178 | 161,281 | 51,822 | 48,624 | 0.66 | 0.66 |
| July 31 | 354,709 | 77,020 | 2,619 | (7,678) | (0.10) | (0.10) |
| October 31 | 311,751 | 87,646 | 6,734 | (13,207) | (0.18) | (0.18) |

The pattern of quarterly earnings is the result of the highly seasonal nature of the business as variations in weather conditions generally result in greater earnings during the winter months. Basic earnings per share are calculated using the weighted average number of shares outstanding during the quarter. The annual amount may differ from the total of the quarterly amounts due to changes in the number of shares outstanding during the year.

## 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

Our management, including the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of the end of the period covered by this Form 10-K. Such disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods required by the United States Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on such evaluation, the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that, as of the end of the period covered by this Form 10-K, our disclosure controls and procedures were effective at the reasonable assurance level.

We routinely review our internal control over financial reporting and from time to time make changes intended to enhance the effectiveness of our internal control over financial reporting. There were no changes to our internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act during the fourth quarter of fiscal 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

December 23, 2009

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting as that term is defined in Rules 13a-15(f) under the Securities Exchange Act of 1934 is 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. The Company's internal control over financial reporting is supported by a program of internal audits and appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written Code of Ethics and Business Conduct adopted by the Company's Board of Directors and applicable to all Company Directors, officers and employees.

Because of the inherent limitations, any system of internal control over financial reporting, no matter how well designed, may not prevent or detect misstatements due to the possibility that a control can be circumvented or overridden or that misstatements due to error or fraud may occur that are not detected. Also, projections of the effectiveness to future periods are subject to the risk that the internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures included in such controls may deteriorate.

We have conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based upon such evaluation, our management concluded that as of October 31, 2009, our internal control over financial reporting was effective.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued its report on the effectiveness of the Company's internal control over financial reporting as of October 31, 2009.

Piedmont Natural Gas Company, Inc.

/s/ Thomas E. Skains
Thomas E. Skains
Chairman, President and Chief Executive Officer

/s/ David J. Dzuricky
David J. Dzuricky
Senior Vice President and Chief Financial Officer

/s/ Jose M. Simon
Jose M. Simon
Vice President and Controller

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Piedmont Natural Gas Company, Inc.

We have audited the internal control over financial reporting of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the Company maintained, in all material respects, effective internal control over financial reporting as of October 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended October 31, 2009 of the Company and our report dated December 23, 2009 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP
Charlotte, North Carolina
December 23, 2009

## Item 9B. Other Information

None.

# PART III

## Item 10. Directors, Executive Officers and Corporate Governance

Information concerning our executive officers and directors is set forth in the sections entitled "Information Regarding the Board of Directors" and "Executive Officers" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which sections are incorporated in this annual report on Form 10-K by reference. Information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning our Audit Committee and our Audit Committee financial experts is set forth in the section entitled "Committees of the Board" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Ethics and Business Conduct that is applicable to all our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. We have also adopted Special Provisions Relating to the Company's Principal Executive Officer and Senior Financial Officers (Special Provisions) that are part of our Corporate Governance Guidelines and that apply to our principal executive officer, principal financial officer and principal accounting officer. The Code of Ethics and Business Conduct and Special Provisions are available on our website at www.piedmontng.com. If we amend or grant a waiver, including an implicit waiver, from the Code of Ethics and Business Conduct or Special Provisions that apply to the principal executive officer, principal financial officer and controller or persons performing similar functions and that relate to any element of the code enumerated in Item 406(b) of Regulation S-K, we will disclose the amendment or waiver on the "About Us-Corporate Governance" section of our website within four business days of such amendment or waiver.

## Item 11. Executive Compensation

Information for this item is set forth in the sections entitled "Executive Compensation," "Director Compensation," "Compensation Committee Interlocks and Insider Participation," and "Compensation Committee Report" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which sections are incorporated in this annual report on Form 10-K by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information for this item is set forth in the section entitled "Security Ownership of Management and Certain Beneficial Owners" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We know of no arrangement, or pledge, which may result in a change in control.

Information concerning securities authorized for issuance under our equity compensation plans is set forth in the section entitled "Equity Compensation Plan Information" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information for this item is set forth in the section entitled "Independence of Board Members and Related Party Transactions" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Item 14. Principal Accounting Fees and Services

Information for this item is set forth in the table entitled "Fees For Services" in "Proposal 2 – Ratification of the Appointment of Deloitte & Touche LLP As Independent Registered Public Accounting Firm For Fiscal Year 2010" in our Proxy Statement for the 2010 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

## PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements

The following consolidated financial statements for the year ended October 31, 2009, are included in Item 8 of this report as follows:



(a) 2. Supplemental Consolidated Financial Statement Schedules

None

Schedules and certain other information are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(a) 3. Exhibits

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses. Upon written request of a shareholder, we will provide a copy of the exhibit at a nominal charge.

The exhibits numbered 10.1 through 10.18 are management contracts or compensatory plans or arrangements.

3.1 Restated Articles of Incorporation of Piedmont Natural Gas Company, Inc., dated as of March 2009 (Exhibit 3.1, Form 10-Q for the quarter ended July 31, 2009).

3.2 Copy of Certificate of Merger (New York) and Articles of Merger (North Carolina), each dated March 1, 1994, evidencing merger of Piedmont Natural Gas Company, Inc., with and into PNG Acquisition Company, with PNG Acquisition Company being renamed "Piedmont Natural Gas Company, Inc." (Exhibits 3.2 and 3.1, Registration Statement on Form 8-B, dated March 2, 1994).

3.3 By-Laws of Piedmont Natural Gas Company, Inc., dated December 15, 2006 (Exhibit 3.3, Form 10-K for the fiscal year ended October 31, 2007).

4.1 Note Agreement, dated as of September 21, 1992, between Piedmont and Provident Life and Accident Insurance Company (Exhibit 4.30, Form 10-K for the fiscal year ended October 31, 1992).

4.2 Amendment to Note Agreement, dated as of September 16, 2005, by and between Piedmont and Provident Life and Accident Insurance Company (Exhibit 4.2, Form 10-K for the fiscal year ended October 31, 2007).

4.3 Indenture, dated as of April 1, 1993, between Piedmont and The Bank of New York Mellon Trust Company, N.A. (as successor to Citibank, N.A.), Trustee (Exhibit 4.1, Form S-3 Registration Statement No. 33-59369).

4.4 Medium-Term Note, Series A, dated as of October 6, 1993 (Exhibit 4.8, Form 10-K for the fiscal year ended October 31, 1993).

4.5 First Supplemental Indenture, dated as of February 25, 1994, between PNG Acquisition Company, Piedmont Natural Gas Company, Inc., and Citibank, N.A., Trustee (Exhibit 4.2, Form S-3 Registration Statement No. 33-59369).

4.6 Medium-Term Note, Series A, dated as of September 19, 1994 (Exhibit 4.9, Form 10-K for the fiscal year ended October 31, 1994).

4.7 Form of Master Global Note (Exhibit 4.4, Form S-3 Registration Statement No. 33-59369).

4.8 Pricing Supplement of Medium-Term Notes, Series B, dated October 3, 1995 (Exhibit 4.10, Form 10-K for the fiscal year ended October 31, 1995).

4.9 Pricing Supplement of Medium-Term Notes, Series B, dated October 4, 1996 (Exhibit 4.11, Form 10-K for the fiscal year ended October 31, 1996).

4.10 Form of Master Global Note, executed September 9, 1999 (Exhibit 4.4, Form S-3 Registration Statement No. 333-26161).

4.11 Pricing Supplement of Medium-Term Notes, Series C, dated September 15, 1999 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement Nos. 33-59369 and 333-26161).

4.12 Pricing Supplement No. 3 of Medium-Term Notes, Series C, dated September 26, 2000 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement No. 333-26161).

4.13 Form of Master Global Note, executed June 4, 2001 (Exhibit 4.4, Form S-3 Registration Statement No. 333-62222).

4.14 Pricing Supplement No. 1 of Medium-Term Notes, Series D, dated September 18, 2001 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement No. 333-62222).

4.15 Second Supplemental Indenture, dated as of June 15, 2003, between Piedmont and Citibank, N.A., Trustee (Exhibit 4.3, Form S-3 Registration Statement No. 333-106268).

4.16 Form of 5% Medium-Term Note, Series E, dated as of December 19, 2003 (Exhibit 99.1, Form 8-K, dated December 23, 2003).

4.17 Form of 6% Medium-Term Note, Series E, dated as of December 19, 2003 (Exhibit 99.2, Form 8-K, dated December 23, 2003).

4.18 Third Supplemental Indenture, dated as of June 20, 2006, between Piedmont Natural Gas Company, Inc. and Citibank, N.A., as trustee (Exhibit 4.1, Form 8-K dated June 20, 2006).

4.19 Form of 6.25% Insured Quarterly Note Series 2006, Due 2036 (Exhibit 4.2 (as included in Exhibit 4.1), Form 8-K dated June 20, 2006).

4.20 Agreement of Resignation, Appointment and Acceptance dated as of March 29, 2007, by and among the registrant, Citibank, N.A., and The Bank of New York Trust Company, N.A. (Exhibit 4.1, Form 10-Q for quarter ended April 30, 2007).

Compensatory Contracts:

10.1 Form of Director Retirement Benefits Agreement with outside directors, dated September 1, 1999 (Exhibit 10.54, Form 10-K for the fiscal year ended October 31, 1999).

10.2 Establishment of Measures for Long-Term Incentive Plan 10 (filed in Form 8-K dated October 20, 2006, as Item 1.01).

10.3 Employment Agreement with David J. Dzuricky, dated December 1, 1999 (Exhibit 10.37, Form 10-K for the fiscal year ended October 31, 1999).

| | |
|---|---|
| 10.4 | Employment Agreement with Thomas E. Skains, dated December 1, 1999 (Exhibit 10.40, Form 10-K for the fiscal year ended October 31, 1999). |
| 10.5 | Employment Agreement with Franklin H. Yoho, dated March 18, 2002 (Exhibit 10.23, Form 10-K for the fiscal year ended October 31, 2002). |
| 10.6 | Employment Agreement with Michael H. Yount, dated May 1, 2006 (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2006). |
| 10.7 | Employment Agreement with Kevin M. O'Hara, dated May 1, 2006 (Exhibit 10.2, Form 10-Q for the quarter ended April 30, 2006). |
| 10.8 | Form of Severance Agreement with Thomas E. Skains, dated September 4, 2007 (Substantially identical agreements have been entered into as of the same date with David J. Dzuricky, Franklin H. Yoho, Michael H. Yount, Kevin M. O'Hara, June B. Moore and Jane R. Lewis-Raymond) (Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2007). |
| 10.9 | Schedule of Severance Agreements with Executives (Exhibit 10.2a, Form 10-Q for the quarter ended July 31, 2007). |
| 10.10 | Piedmont Natural Gas Company, Inc. Incentive Compensation Plan (Exhibit 10.1, Form 8-K dated March 3, 2006). |
| 10.11 | Restricted Stock Award Agreement between Piedmont Natural Gas Company, Inc. and Thomas E. Skains, dated September 1, 2006 (Exhibit 10.26, Form 10-K for the fiscal year ended October 31, 2006). |
| 10.12 | Form of Performance Unit Award Agreement (Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2007). |
| 10.13 | Resolution of Board of Directors, September 7, 2007, establishing compensation for non-management directors (Exhibit 10.23, Form 10-K for the fiscal year ended October 31, 2007). |
| 10.14 | Incentive Compensation Plan Interpretive Guidelines as of September 7, 2007 (Exhibit 10.24, Form 10-K for the fiscal year ended October 31, 2007). |
| 10.15 | Piedmont Natural Gas Company, Inc. Voluntary Deferral Plan, dated as of December 8, 2008, effective November 1, 2008 (Exhibit 10.1, Form 10-Q for quarter ended January 31, 2009). |
| 10.16 | Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan, dated as of December 8, 2008, effective January 1, 2009 (Exhibit 10.2, Form 10-Q for quarter ended January 31, 2009). |

10.17 Piedmont Natural Gas Company Employee Stock Purchase Plan, amended and restated as of April 1, 2009 (Exhibit 4.1, Form 8-K dated April 13, 2009).

10.18 Amendment No. 1 to Director Retirement Benefits Agreements with outside directors, dated as of December 31, 2008 (Exhibit 10.1, Form 10-Q for quarter ended July 31, 2009).

Other Contracts:

10.19 Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, effective January 1, 2004, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2004).

10.20 First Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of July 31, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.28, Form 10-K for the fiscal year ended October 31, 2006).

10.21 Amendment by Written Consent to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of August 28, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.29, Form 10-K for the fiscal year ended October 31, 2006).

10.22 Amendment by Written Consent to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of September 20, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.30, Form 10-K for the fiscal year ended October 31, 2006).

10.23 Equity Contribution Agreement, dated as of November 12, 2004, between Columbia Gas Transmission Corporation and Piedmont Natural Gas Company (Exhibit 10.1, Form 8-K dated November 16, 2004).

10.24 Construction, Operation and Maintenance Agreement by and Between Columbia Gas Transmission Corporation and Hardy Storage Company, LLC, dated November 12, 2004 (Exhibit 10.2, Form 8-K dated November 16, 2004).

10.25 Operating Agreement of Hardy Storage Company, LLC, dated as of November 12, 2004 (Exhibit 10.3, Form 8-K dated November 16, 2004).

10.26 Guaranty of Principal dated as of June 29, 2006, by Piedmont Energy Partners, Inc. in favor of U.S. Bank National Association, as agent (Exhibit 10.1, Form 8-K dated July 5, 2006).

10.27 Residual Guaranty dated as of June 29, 2006, by Piedmont Energy Partners, Inc. in favor of U.S Bank National Association, as agent (Exhibit 10.2, Form 8-K dated July 5, 2006).

10.28 Credit Agreement dated as of April 25, 2006 among Piedmont Natural Gas Company, Inc. and Bank of America, N.A. as Administrative Agent, Swing Line Lender and L/C Issuer, and The Other Lenders Party Hereto (Exhibit 10.1, Form 10-Q for the quarter ended January 31, 2008).

10.29 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Bank of America, N.A., dated October 27, 2008 (Exhibit 10.32, Form 10-K for the year ended October 31, 2008).

10.30 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Branch Banking and Trust Company, dated October 29, 2008 (Exhibit 10.33, Form 10-K for the year ended October 31, 2008).

10.31 Credit Agreement dated as of December 3, 2008 among Piedmont Natural Gas Company, Inc., Bank of America, N.A., as Administrative Agent, and the Other Lenders Party Thereto (Exhibit 10.3, Form 10-Q for the quarter ended January 31, 2009).

10.32 Amended and Restated Revolving Credit Facility dated December 1, 2008 between Piedmont Natural Gas Company, Inc. and Bank of America, N.A. (Exhibit 10.4, Form 10-Q for the quarter ended January 31, 2009).

10.33 Amended and Restated Revolving Credit Facility dated December 1, 2008 between Piedmont Natural Gas Company, Inc. and Branch Banking and Trust Company (Exhibit 10.5, Form 10-Q for the quarter ended January 31, 2009).

10.34 Second Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 2, 2009 (Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2009).

10.35 Settlement Agreement by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 29, 2009 (Exhibit 10.1, Form 8-K dated August 4, 2009).

10.36 Third Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC by and between Georgia Natural Gas Company and Piedmont Energy Company, dated July 29, 2009 (Exhibit 10.2, Form 8-K dated August 4, 2009).

10.37 Assignment and Assumption between Citibank, N.A. and Northern Trust Company, dated as of September 18, 2009.

12 Computation of Ratio of Earnings to Fixed Charges.

21 List of Subsidiaries.

23.1 Consent of Independent Registered Public Accounting Firm.

31.1 Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.

31.2 Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.

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.

Piedmont Natural Gas Company, Inc.
(Registrant)

By: /s/ Thomas E. Skains
Thomas E. Skains
Chairman of the Board, President
and Chief Executive Officer

Date: December 23, 2009

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 dates indicated.

| Signature | Title |
|---|---|
| /s/ Thomas E. Skains<br>Thomas E. Skains | Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer) |
| Date: December 23, 2009 | |
| /s/ David J. Dzuricky<br>David J. Dzuricky | Senior Vice President and Chief Financial Officer (Principal Financial Officer) |
| Date: December 23, 2009 | |
| /s/ Jose M. Simon<br>Jose M. Simon | Vice President and Controller (Principal Accounting Officer) |
| Date: December 23, 2009 | |

| Signature | Title |
|---|---|
| /s/ Jerry W. Amos<br>Jerry W. Amos | Director |
| /s/ E. James Burton<br>E. James Burton | Director |
| /s/ Malcolm E. Everett III<br>Malcolm E. Everett III | Director |
| John W. Harris | Director |
| /s/ Aubrey B. Harwell, Jr.<br>Aubrey B. Harwell, Jr. | Director |
| /s/ Frank B. Holding, Jr.<br>Frank B. Holding, Jr. | Director |
| /s/ Frankie T. Jones, Sr.<br>Frankie T. Jones, Sr. | Director |
| /s/ Vicki McElreath<br>Vicki McElreath | Director |
| /s/ Minor M. Shaw<br>Minor M. Shaw | Director |
| /s/ Muriel W. Sheubrooks<br>Muriel W. Sheubrooks | Director |
| /s/ David E. Shi<br>David E. Shi | Director |

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# our shareholders

**ANNUAL MEETING**

The 2010 Annual Meeting of Shareholders will be held at the corporate office of the Company, 4720 Piedmont Row Drive, Charlotte, North Carolina 28210, at 8:30 a.m. on Friday, February 26, 2010. This Summary Annual Report and the financial statements contained herein are presented solely for the general information of security holders and others and are not intended for use in connection with any purchase or sale of securities.

**WRITTEN REQUESTS FOR COMMON STOCK TRANSFERS AND OTHER SHAREHOLDER INQUIRIES REGARDING:**

- Direct deposit of dividend payments
- IRS Form 1099s
- Replacement of dividend checks
- Automatic bank draft for stock purchases
- Lost or stolen stock certificates
- Consolidation of accounts
- Change of address
- Dividend Reinvestment & Stock Purchase Plan

American Stock Transfer & Trust Company
59 Maiden Lane, Plaza Level, New York, New York 10038
Tel: 800-937-5449
www.amstock.com

**COMMON STOCK LISTING**

Our common stock is listed and traded on the New York Stock Exchange under the symbol "PNY." The abbreviations "PiedmontNG" or "PiedNG" appear in various stock listings.

**DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN**

The Dividend Reinvestment and Stock Purchase Plan provides investors and shareholders with a convenient method for reinvesting dividends and purchasing shares of common stock directly from the Company without paying any service charges or brokerage commissions.

Plan Features:

- Initial investment of $250, up to $120,000 per calendar year
- Voluntary cash purchases from $25 per payment to $120,000 per calendar year
- 5% discount on shares purchased with reinvested dividends
- Deposit share certificates for safekeeping
- Automatic monthly investing available

**Call 800-937-5449** for information about the Plan, including a prospectus and enrollment forms.

**FINANCIAL INQUIRIES**

Anyone seeking financial information should contact:
Nick Giaimo
Investor Relations
Tel: 704-731-4952
nick.giaimo@piedmontng.com

**MEDIA INQUIRIES**

The media should contact:
David L. Trusty
Managing Director – Public Relations
Tel: 704-731-4391
david.trusty@piedmontng.com

**PUBLICATIONS AVAILABLE**

To view a copy of press releases or the most recent financial results, please visit the Company's web site: www.piedmontng.com

Upon request, the Company will provide the following:
• Summary Annual Report • Form 10-K • Form 10-Q

**INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

Deloitte & Touche LLP
1100 Carillon Building, 227 West Trade Street
Charlotte, North Carolina 28202

**STREET ADDRESS**

Piedmont Natural Gas
4720 Piedmont Row Drive, Charlotte, North Carolina 28210
Tel: 704-364-3120

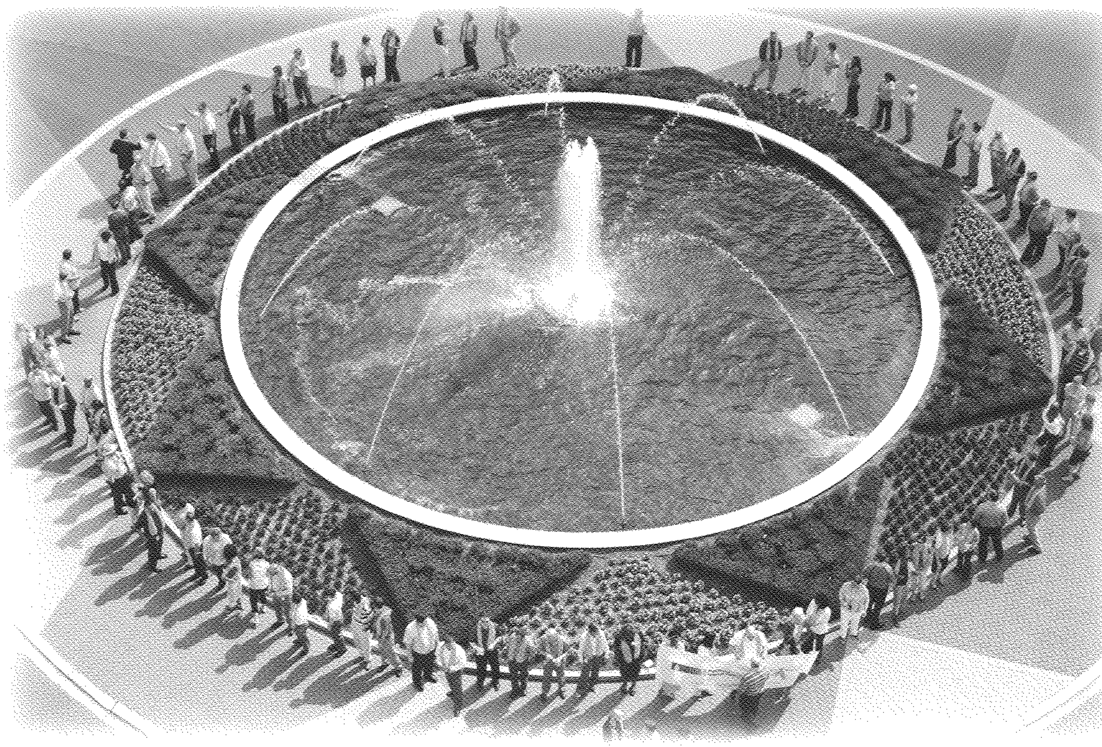
**MAILING ADDRESS**

Piedmont Natural Gas
Post Office Box 33068, Charlotte, North Carolina 28233

**ON THE WEB**

www.piedmontng.com

Piedmont Natural Gas is an Equal Opportunity Employer.



Share the warmth.

Small change to change lives.

A simple way to help neighbors in need pay their home energy bills.