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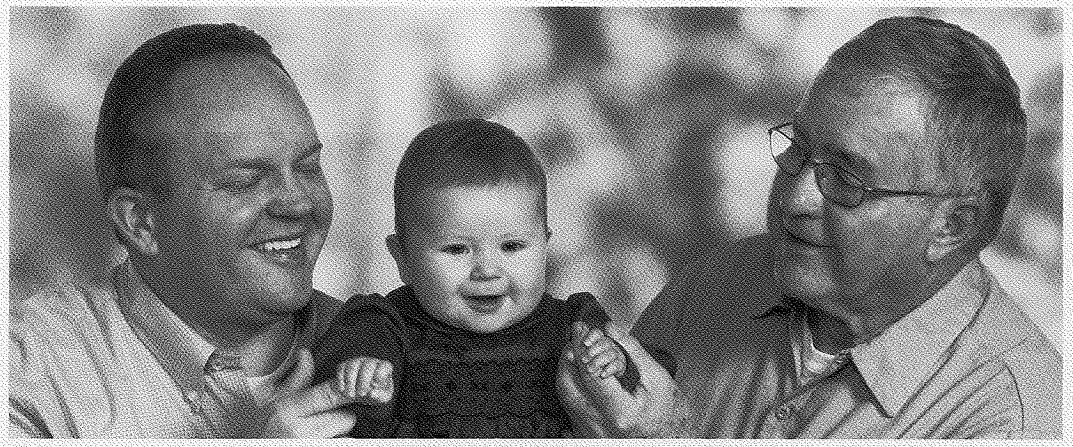
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Piedmont Natural Gas 2008 Annual Report

Responsible Choices



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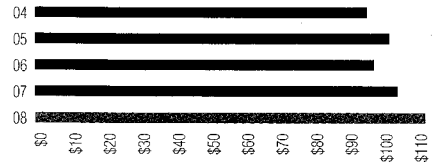


Financial Highlights

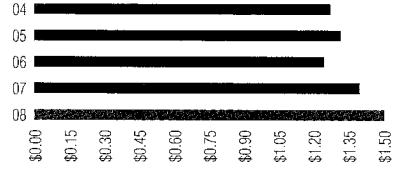
In thousands except per share amounts, degree days and customer additions	2008	2007	Percent Change
Earnings and Dividends			
Net Income	**$ 110,007**	$ 104,387	5.4 %
Earnings Per Share of Common Stock:			
Basic	**$ 1.50**	$ 1.41	6.4 %
Diluted	**$ 1.49**	$ 1.40	6.4 %
Dividends Per Share	**$ 1.03**	$ 0.99	4.0 %
Margin, Revenues and Volumes			
Margin (Operating Revenues less Cost of Gas)	**$ 552,973**	$ 524,165	5.5 %
Operating Revenues	**$ 2,089,108**	$ 1,711,292	22.1 %
Gas Volumes – Dekatherms:			
Sales	**110,801**	105,606	4.9 %
Transportation	**99,450**	100,398	(0.9)%
Total System Throughput	**210,251**	206,004	2.1 %
Secondary Market Sales	**53,442**	42,049	27.1 %
Degree Days – System Average	**3,195**	2,977	7.3 %
Construction and Customer Additions			
Utility Construction Expenditures	**$ 181,001**	$ 135,231	33.8 %
Gross Customer Additions	**20,500**	30,400	(32.6)%
Net Utility Plant – Year End	**$2,240,834**	$ 2,141,537	4.6 %
Common Stock			
Book Value Per Share – Year End	**$ 12.11**	$ 11.84	2.3 %
Market Value Per Share – Year End	**$ 32.92**	$ 25.53	28.9 %
Average Shares of Common Stock:			
Basic	**73,334**	74,250	(1.2)%
Diluted	**73,612**	74,472	(1.2)%

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.

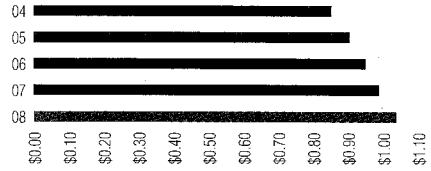
Net Income *In millions*



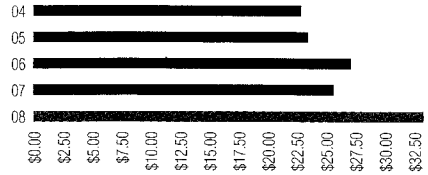
Earnings Per Share *Diluted*



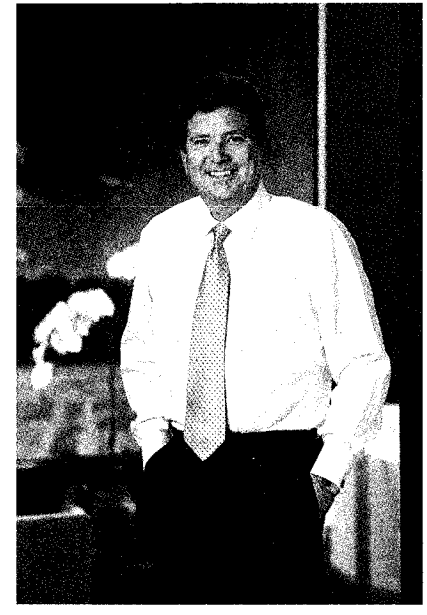
Dividends Per Share



Market Value Per Share *At October 31*



Fellow Shareholders



Our fiscal 2008 was an extraordinary year of challenge and change for businesses and consumers. We witnessed unprecedented volatility in energy commodity prices, a crisis in worldwide financial markets and consumer confidence, and an economic recession. Through it all, your Company delivered record financial performance, dividend growth, and superior shareholder returns. We enter fiscal year 2009 in a financially strong position with an excellent balance sheet, continued access to capital markets and poised for future growth opportunities. All of these accomplishments were made possible by the hard work and dedication of my 1,821 talented and dedicated teammates at Piedmont Natural Gas.

In fiscal year 2008, we achieved record net income and earnings per diluted share of $110 million and $1.49, respectively. These results were positively influenced by top-line margin growth from continued new customer additions and expense reductions from ongoing cost management programs.

Our total shareholder returns (stock price appreciation and dividends) for the one and three-year periods ending October 31, 2008 were 34 percent and 56 percent, respectively, placing your Company in the 100th and 96th percentiles, respectively, of our industry peer group. In March, your Board of Directors increased the dividend for the 30th consecutive year. The new $1.04 annualized dividend was a four percent increase over the prior year.

Our financial strength and continued growth reflect the value that our customers place on natural gas as a clean, efficient and reliable source of energy for their homes and businesses, and their confidence in Piedmont to provide them with quality customer service. We added 20,500 new customers to our distribution systems in 2008, a gross customer addition growth rate of two percent, and we remain one of the fastest-growing natural gas utilities in the nation. In March 2008, and for the second consecutive year, Piedmont Natural Gas was ranked highest in the South region in business customer satisfaction by a J.D. Power and Associates study.

The theme of this year's annual report to shareholders is "Responsible Choices." It reflects our commitment to make responsible decisions on behalf of our shareholders, our customers, our environment, our communities and our employees. At Piedmont, we are committed to taking responsible actions and making responsible choices – today and for the future. There is one matter of particular interest for which we need your active support. The current 15 percent maximum tax rate on corporate dividends is scheduled to expire in 2010. An extension of this tax rate is important for utility shareholders and customers, and it would assist your Company and other energy utilities in raising cost-effective capital for future infrastructure investment to meet our nation's growing energy needs. I encourage you to partner with other energy utility shareholders by visiting www.defendmydividend.org and signing the petition in support of our extension efforts.

This year's theme also ties to my theme as 2009 Chairman of the American Gas Association – "Natural Gas: America's Responsible Energy Choice." I firmly believe natural gas is uniquely positioned to provide near-term and long-term solutions to our nation's energy and environmental challenges. We deliver a clean, efficient and abundant energy resource that provides an immediate, low carbon, domestic energy choice for America's consumers. When our customers use natural gas directly to warm their homes, heat their water and cook their food, they are using natural gas in the most efficient and environmentally responsible way possible. They are making the "responsible" energy choice.

On behalf of your Board, management and employee team, I look forward to the challenges and opportunities ahead and thank you for your continued support.



Thomas E. Skains

Chairman, President and Chief Executive Officer

January 5, 2009

Piedmont Natural Gas

Our Customers

While 2008 was a year of economic challenge and uncertainty, Piedmont continued to generate quality growth in our markets, adding new customers throughout our North Carolina, South Carolina, and Tennessee service areas. In fact, despite the economic downturn, Piedmont's gross customer additions totaled 20,500 in 2008 yielding an annual customer growth rate of two percent. As a result, we remained one of the fastest-growing natural gas distribution companies in the nation, again demonstrating the underlying resilience and vitality of the communities and regions we serve.

These results were made possible in no small measure by the hard work and persistence of Piedmont's team of sales and marketing professionals. The message they delivered to customers and potential customers was simple: natural gas is the comfortable and responsible energy choice. Comfortable to our customers for heating their home and businesses, providing hot water, cooking their food and drying their clothes. Responsible to our environment as a clean, efficient energy product with a lower carbon footprint than electricity, propane or fuel oil. And, responsible to our economy and our national security as a domestically abundant energy source.

"In 2008, we were determined to grow our customer base despite difficult economic and market conditions. We owe our success to the clarity of our message, the focus of our sales team, and the positive business relationships we have established over the years."

Frank Yoho, Senior Vice President - Commercial Operations.

This message took hold in our residential conversion markets in 2008. Here, customer growth is achieved when an existing homeowner makes the decision to switch from another energy product, such as electricity or propane, to natural gas for home heating or water heating. The sales process in the conversion market is longer. It typically involves repeated sales calls to the homeowner and requires a capital outlay from the customer to purchase new natural gas equipment. During 2008, we were successful in converting 1,860 existing homes to natural gas, exceeding our 2007 performance in this market segment by 17 percent.

Our success in the conversion markets partially offset slower growth in our residential new construction and commercial markets in 2008. Even with the decline in general economic conditions, these market segments contributed significant new customer growth during the year. We added 16,280 residential new construction customers and 2,360 new commercial customers to our distribution systems in 2008.



Beyond our efforts in the residential and commercial markets, we also devoted considerable time and resources to our major account customers. For these larger commercial and industrial accounts, Piedmont provides a variety of specialized services to satisfy their unique energy challenges. Our highly trained and qualified major account representatives solve energy equipment problems, propose cost saving measures and provide technical services on a day-to-day basis.



June Moore, Vice President of Customer Service, talks to Jody Kelly and Jennifer Blackburn about customer service initiatives.



As customers of Piedmont Natural Gas, employee Todd Hackler and his family enjoy the benefits of cooking with natural gas.

In the area of customer service, we strive to exceed customer expectations and continue to implement service improvements. Our customer service representatives answered an average of 85 percent of all customer calls during the year within 20 seconds or less. We have met our 80/20 customer contact center goal for three consecutive years and believe it is an important aspect of the overall customer service experience at Piedmont. In March of 2008, a study by J.D. Power and Associates ranked Piedmont #1 in the South for business customer satisfaction among natural gas utilities for the second consecutive year. While we are pleased with these results, we are continuously looking for ways to improve our customer service processes.

At Piedmont, that begins with listening to our customers. In 2008, we added a telephone customer survey option that allows our customers to give us immediate feedback on their call center experience. Hearing from our customers at this important touch point broadens our understanding of the customer experience and allows us to identify specific areas for improvement.

Other service improvements we have implemented this past year include expanding the number of options through which customers can choose to receive and pay their bills. Customers can now receive electronic or hard copies of their bill, and they can choose to pay in person, by mail, through a bank draft, by phone or online with a credit or debit card. Piedmont is maximizing customer conveniences, and we are pleased to offer the credit and debit card transactions as free services to our customers.

Also in 2008, Piedmont expanded to more than 240 alternative paystations throughout our North Carolina, South Carolina and Tennessee service areas. These paystations, which include local grocery stores and Western Union offices, offer customers added flexibility and convenience.

"Our focus on best-in-class customer service has provided us with the motivation to continuously improve the processes and systems underlying our service. My teammates across the entire organization have really embraced this effort."

June Moore, Vice President - Customer Service

Our Communities

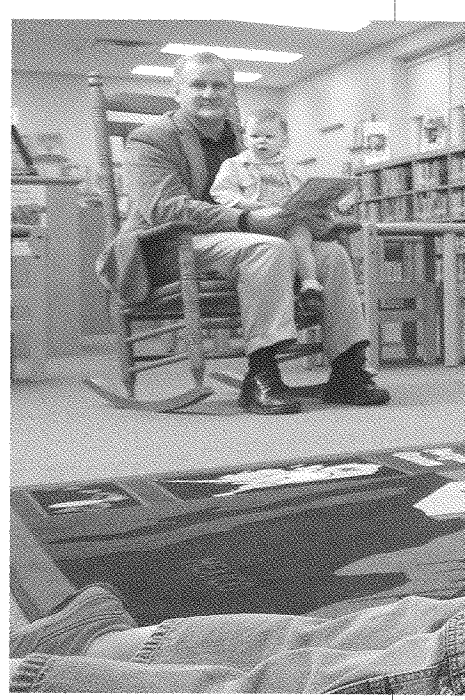
Piedmont is committed to improving the quality of life in the communities we serve. We believe that we have a responsibility to improve the economic and social vitality of the cities and towns where our employees live and work. We do this through the financial support of our Company and the Piedmont Natural Gas Foundation and the time spent by our employees as service volunteers and community leaders.

In 2008, the Piedmont Natural Gas Foundation contributed more than $800,000 to 145 non-profit organizations that share our goals in the areas of low-income energy assistance, literacy and education, community care and support, and environmental stewardship.

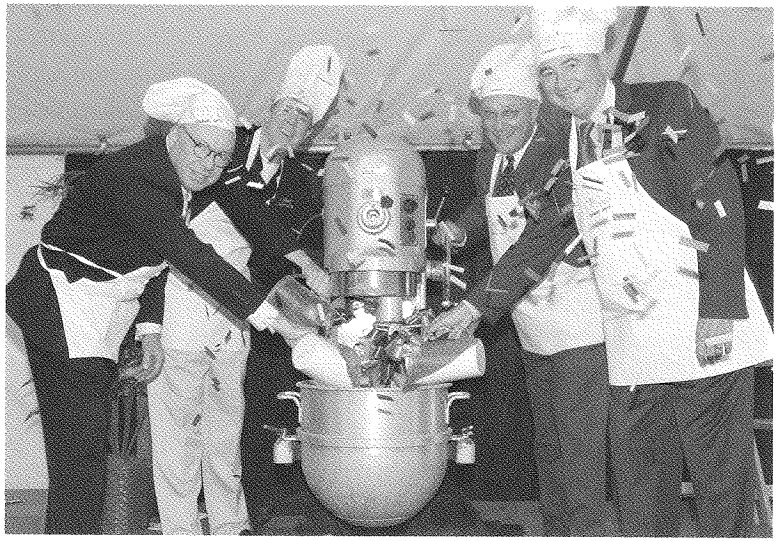
"We live and work in the communities we serve, and we know that our success depends on the strength of the people and businesses that make up our local communities."

Dave Dzuricky, Senior Vice President & Chief Financial Officer

Many of our friends and neighbors faced financial hardship in 2008 like never before. We provided assistance for many of these individuals and families through our Share the Warmth program. Share the Warmth is an energy-assistance program that helps low-income individuals and families pay their energy bills. Over the past five years, we have distributed nearly $1 million through Share the Warmth to local relief agencies throughout our three state service area. We also worked with other energy utilities in 2008 to advocate additional federal funding for the Low Income Home Energy Assistance Program (LIHEAP). In September, the President and Congress appropriated full funding for the LIHEAP program at a record level of $5.1 billion. This was a significant event on behalf of our nation's most vulnerable energy consumers.



One of the Foundation's lead grants to support literacy and education was a multi-year $150,000 grant to the Governor's Books from Birth Foundation in Tennessee to support Imagination Library programs. Created in 1996 by Dolly Parton in her hometown of Sevierville, Tennessee, the Imagination Library mails a new, age-appropriate, hardcover book every month to registered children from birth until age five – at no cost to the family, regardless of income.



Dave Dzuricky, Senior Vice President and Chief Financial Officer, attends the ground breaking for the new culinary center at Central Piedmont Community College in Charlotte, NC.



As a volunteer for "Books from Birth," employee Pam Thomas reads to children at a library in Nashville, TN.

"Piedmont's contribution will put quality books into the hands of almost 11,000 of Tennessee's youngest citizens for a full year – children who may not have otherwise been exposed to books and reading prior to entering Kindergarten. We are pleased to have Piedmont on board and look forward to celebrating the fruits of their sponsorship of this important program for many more years to come."

Governor Phil Bredesen, The State of Tennessee

The Foundation also made charitable gifts of more than $250,000 in 2008 to local United Way chapters throughout our service territory. This is in addition to $570,000 in personal gift pledges from our employees.

Our Matching Gifts program gives employees the opportunity to leverage their financial support of nonprofit organizations with a matching Company contribution up to a specified level per employee each year. In 2008, more than 500 employees participated in our Matching Gifts program resulting in nearly $80,000 in eligible matching gifts.

We recognize that our communities need more than our financial support – they need our employees' time and talent. For that reason, each member of Piedmont's Leadership Council, representing the top 40 managers across the Company, serves as a volunteer or on the board of directors of at least one nonprofit organization in our service territory.

In fact, our employees throughout the organization choose to be active in local community service. From the Relay for Life and the American Heart Association to Big Brothers Big Sisters and Junior Achievement – our employees share their energy and their passion for giving with our communities and we fully support their efforts.

Our Environment

For much of 2008, energy and environmental issues were on the minds of most Americans as the national discussion about energy decisions and their impact on the environment and the economy took on a greater sense of urgency. As gasoline prices climbed higher and as presidential campaigns took place, Americans began to focus more clearly on the energy choices we make – both as a country and as individuals.

At Piedmont, we believe our nation's energy and environmental goals can best be met by using a diverse portfolio of energy resources. We must further develop our renewable energy resources such as wind and solar; we need to increase our use of nuclear energy and utilize clean coal technologies; we must use natural gas to its greatest potential in order to realize its promise as a unique energy and environmental resource; and we must promote cost-effective energy efficiency and conservation programs in order to use all energy wisely. The reality is that energy choices surround us – what we must do is make responsible energy choices for our environment and for our future.

"As a natural gas utility, we recognize our role in promoting the wise and efficient use of natural gas. We are doing this through energy efficiency and conservation programs that benefit our customers and our shareholders."

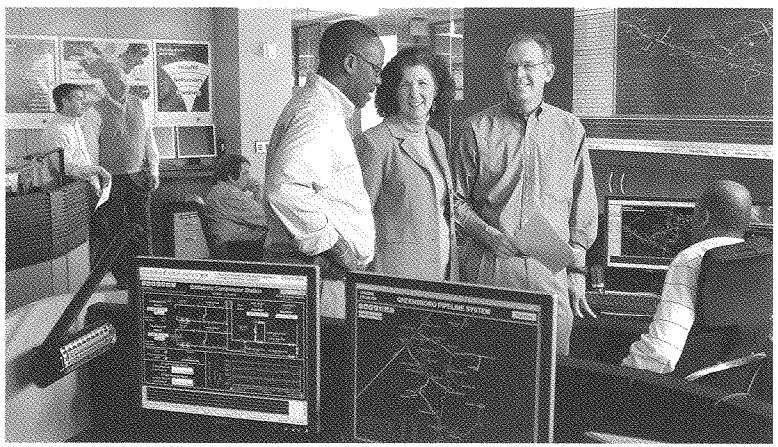
Jane Lewis-Raymond, Vice President - General Counsel

"Responsible energy choices" for our environment means choosing the cleanest energy sources available to meet energy demand and using those energy sources in the most efficient way possible. Piedmont Natural Gas is fortunate to distribute an energy resource that is uniquely positioned among all energy choices to play a vital role in meeting our nation's energy and environmental goals. Natural gas is an energy source that is clean, efficient and abundant.

Natural gas is clean. Natural gas is the cleanest burning of all fossil fuels – emitting 43 percent less carbon dioxide than coal, 28 percent less carbon dioxide than oil and 17 percent less carbon dioxide than propane.

Natural gas is efficient. In today's world, energy efficiency translates into "green" energy. The more efficiently energy is transported from the source of its production to the site of its end use, the less energy is consumed and the lower the carbon dioxide emissions. Our nation's nat-





Frank Yoho, Senior Vice President of Commercial Operations, monitors the delivery of clean-burning natural gas with members of his team in Piedmont's Gas Control room.



The direct use of natural gas by customers to heat their water or warm their home is its best and most efficient use.

ural gas transmission and distribution pipeline system is one of the most efficient energy delivery systems in the world. In fact, 90 percent of the energy value of our natural gas is retained from the source of production to the site of end use, far exceeding the energy efficiency of our nation's electric generation, transmission and distribution systems. Natural gas also has a smaller carbon footprint than electricity when used directly in homes and businesses.

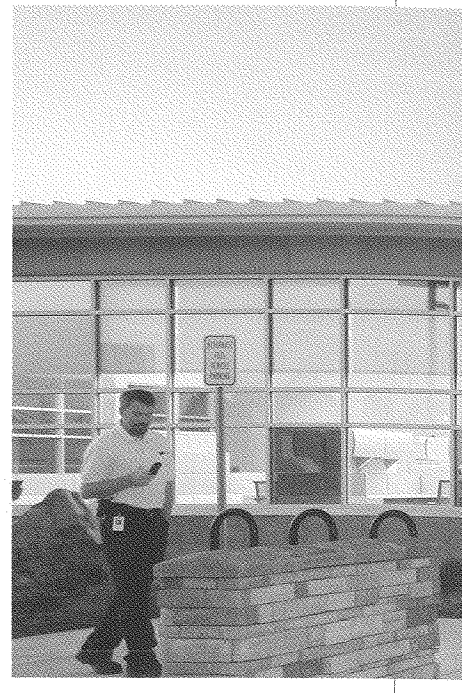
Natural gas is abundant. Natural gas is one of our most abundant domestic energy resources. In order to meet our nation's growing appetite for this clean and efficient form of energy we need access to our nation's onshore and offshore natural gas resources and the development of pipeline and storage infrastructure. More than 80 percent of the natural gas consumed in America is produced in our country with another 17 percent produced in Canada. Only three percent of our natural gas supplies currently come from supply sources outside of North America, although global natural gas supplies are abundant as well. New exploration and production technologies allow our nation's natural gas resources to be produced in a safe and environmentally sensitive manner. Domestic natural gas production and reserve additions are growing with the development of unconventional shale gas basins across the nation. In addition, significant capacity expansions have been completed or are underway at liquefied natural gas, or "LNG," import terminals on our nation's coastline to receive supplemental supplies of natural gas when needed. Access to our domestic natural gas resources and the development of energy infrastructure should be major principles in our nation's energy and environmental policy goals.

Our Environment

We also believe that it is important for energy utilities and their state regulatory commissions to adopt innovative rate structures and programs that do not discourage, but instead encourage, energy efficiency and customer conservation. Traditional volumetric rate designs that provide incentives for utilities to seek increased energy usage are no longer appropriate in an era when policy objectives are focused on energy efficiency, climate change and carbon emissions. Instead, we urge the creation of incentives for energy efficiency and conservation programs, including those that promote the efficient use of natural gas in direct use applications.

In North Carolina, we operate under a permanent margin decoupling tariff, effective November 1, 2008, that separates, or "decouples," the collection of utility margin from the consumption patterns of our residential and commercial customers. This rate design and the accompanying approval of a cost based energy efficiency and conservation program better align the interests of our Company and our customers. In South Carolina, we operate under a rate stabilization mechanism that "decouples" our margin collection with a one year lag. In Tennessee, we are in discussions with other natural gas utilities and energy policy leaders about needed regulatory reform in that state.

In 2008, Piedmont took a leadership role in the formation of The Council for Responsible Energy, a coalition of more than 190 organizations that have joined together to educate consumers and businesses about the benefits of natural gas as the most comfortable and responsible energy choice. As part of that campaign, the Council has developed an online resource, www.comfortableresponsible.org, where visitors can learn ways to use natural gas wisely in their homes and businesses, and find tips and tools to reduce their energy consumption. One of the beneficial features of the online resource is an emissions calculator that allows homeowners to input appliance data and calculate the overall emissions footprint for their households.



Piedmont also took a leadership role in promoting energy efficiency and environmental stewardship in our local business operations in 2008. We announced plans for two Leadership in Energy and Environmental Design (LEED) certified operations buildings that further reinforce our commitment to the wise and efficient use of our energy resources while protecting the environment.



Michael Yount, Senior Vice President of Utility Operations, attends the ground breaking ceremony for Piedmont's LEED designed operations center in Nashville, TN.



Piedmont's new LEED designed operations center in Tarboro, NC opened to employees in October 2008.

LEED certification of a building or structure recognizes a facility that reduces waste and greenhouse gas emissions, and conserves water and energy, both during construction and operations. According to the U.S. Green Building Council which developed the LEED rating system, there are less than 50 LEED certified projects in North Carolina and only 13 in Tennessee. There are just slightly more than 2,000 LEED certified projects in the entire United States.

The first LEED project we announced was our new operations center in Tarboro, North Carolina. This facility was completed and occupied by our employees in 2008. We are awaiting final LEED certification for this project. The second project we announced was our plans for a new operations center in Nashville, Tennessee. We have broken ground for construction of this facility and are scheduled for completion in early 2010.

"Piedmont made a choice to be responsible to our environment with the decision to seek LEED certification for our new operations centers in Tarboro and in Nashville. These new facilities will be a source of pride for our employees and for the communities in which they are located."

Michael Yount, Senior Vice President - Utility Operations

Natural Gas
Comfortable. Responsible.

The Council for Responsible Energy is an industry coalition dedicated to promoting natural gas as the most comfortable and responsible energy choice for consumers and businesses.

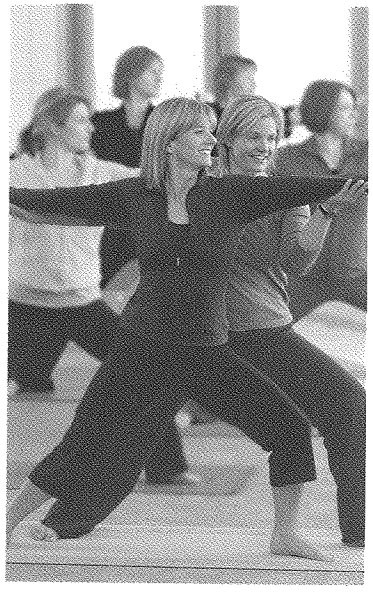
Our Employees

"Piedmont truly stands behind its commitments to employee development, wellness and a work-life balance. It is a responsibility that we embrace and one that has paid dividends many times over whether it involves working together to improve our business processes or coming together to solve a business, service or customer issue."

Kevin O'Hara, Senior Vice President - Corporate & Community Affairs



Jane Lewis-Raymond, General Counsel, participates in a yoga class as part of the Company's wellness program.



Our 2008 results could not have been achieved without the leadership and commitment of our 1,822 employees. Their efforts, grounded in a healthy, high performance culture, have allowed us to meet our current challenges and will allow us to take advantage of the opportunities that lie ahead.

In 2008, we continued to build upon our company culture through a number of initiatives designed to improve the health of our employees while maintaining their high level of performance. Our efforts during the year focused on employee safety and wellness, a positive work environment, professional development and leadership training, and innovation and diversity.

Safety is a vital aspect of employee wellness at Piedmont. It is our highest priority whether in providing service to our customers or in our routine day-to-day work. We include safety as a key component of our company-wide performance plan for every employee and we have been successful in continously improving our safety performance over the last three years.



Piedmont employees in South Carolina attend a company-sponsored training class on industry regulations.

Piedmont's Wellness Program is one of our most successful employee programs with more than 80 percent of all employees participating during 2008. We initiated a health screening process that provides employees with valuable information about their personal health along with suggestions and tips that each employee can adopt to improve their individual health.

This program includes fitness program reimbursement, tobacco cessation programs, weight control programs and monthly promotions or challenges to encourage continued participation. In addition to promoting a healthy workforce and improving the lives of our employees and their families, the program has also helped the Company to more effectively address its healthcare costs.

Employee wellness, however, goes beyond the physical well being of each employee. To enhance productivity and employee satisfaction, Piedmont also offers flexible work arrangements such as alternative work scheduling and telecommuting.

Alternative work scheduling is designed to create the most productive working conditions for employees. Due to family schedules and other considerations, some employees request a work schedule that differs from the traditional work schedule. Our experience shows that enabling employees to take advantage of these

alternate work schedules promotes a better work-life balance and is a powerful employee satisfaction, retention and performance tool. When employees are better able to meet their personal obligations, they are more focused at work. Some of the alternate work schedules include compressed work weeks, flexible hours, part-time work and job sharing.

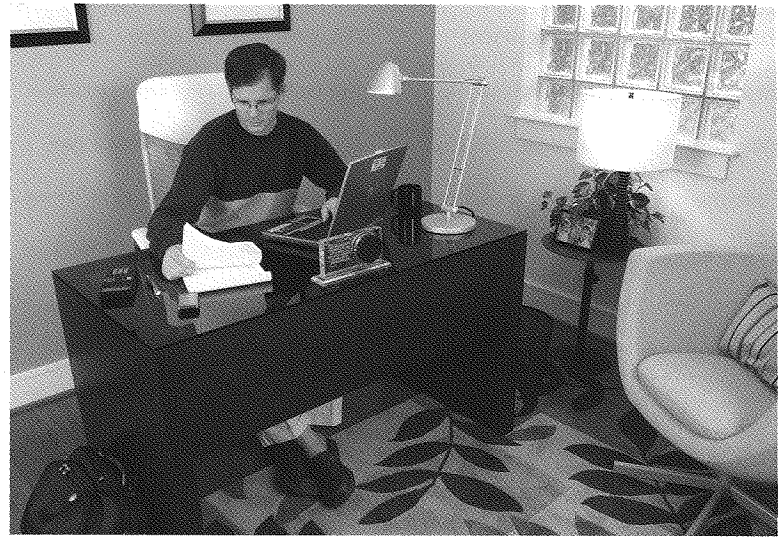
Telecommuting is another program designed to create productive work environments for our employees and has benefited not only Piedmont, but also our environment and our communities. Fewer employees commuting to work every day helps reduce traffic, air pollution, wear and tear on our transportation infrastructure and energy consumption.

We also create opportunities for our employees to develop and grow professionally in order to make the most of their individual skills and capabilities and to contribute to the success of the Company. We regard this as one of our most important responsibilities – to offer our teammates opportunities to learn new skills, to develop as leaders, and to share their experiences and knowledge with others.

Piedmont Pride is our primary leadership development program. It is conducted by certified internal and external facilitators and it is designed to develop the leadership potential of every employee at the Company. The program emphasizes the value of diverse leadership styles, with a focus on how we can work together more effectively to achieve personal, team and Company goals.

PNG University is our in-house educational program that helps employees meet their personal and professional development goals. Classes cover a wide range of topics and provide the skills, knowledge and tools to foster a high-performance culture and build talent within the organization.

Piedmont also supports the educational and professional development of its employees by providing educational assistance to employees who wish to pursue college degrees or other academic course work in their professional field.



John Giles, computer programmer for Piedmont, telecommutes from home in Charlotte, NC.





Members of Piedmont's Diversity Council brainstorm in the Company's new Learning-Innovation-Diversity Center.

Innovation and continuous process improvement have been important parts of Piedmont's culture for many years. By seeking ways to become more efficient and improve our processes we are ensuring that the service we provide our customers will continue to have real value. In 2008, Piedmont launched a new Learning-Innovation-Diversity facility in Charlotte. The facility provides a space where diverse ideas and experiences can come together to discover innovative solutions to unique business challenges and market opportunities. The facility is designed to leverage our diversity by promoting creative thinking, learning and innovation and features a learning library complete with computer access, reference books and other materials.

"Piedmont's culture encourages teamwork and collaboration as a means of achieving desired results. We promote an environment where our employees can bring their diverse perspectives and experiences together to develop innovative solutions for the challenges and opportunities we face as an organization."

Claire Taylor, Managing Director
Corporate Communications & Organizational Effectiveness

FIVE-YEAR COMPARISON FOR THE YEARS ENDED OCTOBER 31, 2004 THROUGH 2008

	2008	2007	2006	2005	2004
Operating Revenues *(in thousands)*:					
Sales and Transportation:					
Residential	**$ 813,032**	$ 743,637	$ 841,051	$ 686,304	$ 624,487
Commercial	**503,317**	418,426	498,956	421,499	360,355
Industrial	**209,341**	190,204	205,384	215,505	179,302
For Power Generation	**25,266**	29,135	22,963	16,248	18,782
For Resale	**12,326**	13,907	11,342	40,122	38,074
Total	**1,563,282**	1,395,309	1,579,696	1,379,678	1,221,000
Secondary Market Sales	**515,968**	308,904	337,278	373,353	301,886
Miscellaneous	**9,858**	7,079	7,654	8,060	6,853
Total	**$2,089,108**	$1,711,292	$1,924,628	$1,761,091	$1,529,739
Gas Volumes — Dekatherms *(in thousands)*:					
System Throughput:					
Residential	**51,909**	50,072	49,119	52,966	54,412
Commercial	**36,766**	33,647	34,476	36,000	35,483
Industrial	**81,780**	79,266	80,490	81,102	83,957
For Power Generation	**30,875**	34,096	26,099	25,591	18,580
For Resale	**8,921**	8,923	8,472	8,779	8,912
Total	**210,251**	206,004	198,656	204,438	201,344
Secondary Market Sales	**53,442**	42,049	40,994	47,057	51,707
Number of Customers Billed *(12 month average)*:					
Residential	**852,586**	835,636	815,579	792,061	771,037
Commercial	**94,045**	93,472	92,692	91,645	90,328
Industrial	**2,937**	2,959	3,008	3,146	3,194
For Power Generation	**20**	15	12	16	13
For Resale	**17**	15	19	15	15
Total	**949,605**	932,097	911,310	886,883	864,587
Average Per Residential Customer:					
Gas Used — Dekatherms	**60.88**	59.92	60.23	66.87	70.57
Revenue	**$ 953.61**	$ 889.90	$ 1,031.23	$ 866.48	$ 809.93
Revenue Per Dekatherm	**$ 15.66**	$ 14.85	$ 17.12	$ 12.96	$ 11.48
Degree Days — System Average:					
Actual	**3,195**	2,977	3,192	3,266	3,331
Normal	**3,358**	3,388	3,386	3,455	3,524
Shares of Common Stock Outstanding at Year End *(in thousands)*	**73,246**	74,208	75,464	76,698	76,670
Number of Shareholders of Record *(at year end)*	**15,109**	15,631	16,280	16,721	16,389
Number of Utility Employees	**1,833**	1,876	2,051	2,124	2,120

Selected Financial Data *(In thousands except per share amounts)*

Years Ended October 31	**2008**	2007	2006	2005	2004
Operating Revenues	**$2,089,108**	$1,711,292	$1,924,628	$1,761,091	$1,529,739
Margin	**$ 552,973**	$ 524,165	$ 523,479	$ 499,139	$ 488,369
Net Income	**$ 110,007**	$ 104,387	$ 97,189	$ 101,270	$ 95,188
Earnings per Share of Common Stock:					
Basic	**$ 1.50**	$ 1.41	$ 1.28	$ 1.32	$ 1.28
Diluted	**$ 1.49**	$ 1.40	$ 1.28	$ 1.32	$ 1.27
Cash Dividends per Share of Common Stock	**$ 1.030**	$ 0.990	$ 0.950	$ 0.905	$ 0.8525
Total Assets	**$3,093,580**	$2,820,318	$2,733,939	$2,602,490	$2,392,164
Long-Term Debt (less current maturities)	**$ 794,261**	$ 824,887	$ 825,000	$ 625,000	$ 660,000

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

Fiscal Year 2008	Operating Revenues	Margin	Operating Income	Net Income (Loss)	Earnings (Loss) Per Share of Common Stock Basic	Earnings (Loss) Per Share of Common Stock Diluted
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)**
Fiscal Year 2007						
January 31	$677,241	$208,485	$81,697	$ 70,716	$ .95	$ .94
April 30	531,579	159,727	50,621	51,120	.69	.69
July 31	224,442	75,158	1,021	(9,140)	(.12)	(.12)
October 31	278,030	80,795	4,008	(8,309)	(.11)	(.11)

Common Stock Information

The following table provides information with respect to the high and low sales prices from the New York Stock Exchange Composite for each quarterly period for the years ended October 31, 2008 and 2007 and the quarterly cash dividends paid per share.

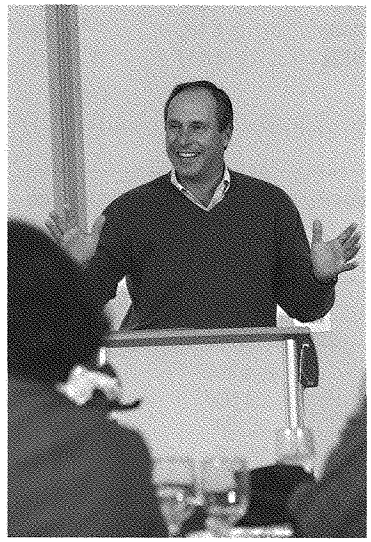
	2008				2007		
Quarter Ended	High	Low	Dividends Per Share	Quarter Ended	High	Low	Dividends Per Share
January 31	**$27.98**	**$24.01**	**25.00¢**	January 31	$28.44	$25.78	24.00¢
April 30	**27.68**	**24.05**	**26.00¢**	April 30	27.50	24.33	25.00¢
July 31	**27.95**	**25.00**	**26.00¢**	July 31	27.50	22.00	25.00¢
October 31	**35.29**	**20.52**	**26.00¢**	October 31	27.50	23.09	25.00¢

Our Shareholders

ANNUAL MEETING

The 2009 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, March 6, 2009. The formal notice of the meeting, 2008 Form 10-K, proxy statement and form of proxy card are being mailed to holders of record of common stock along with this Summary Annual Report.

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.



Kevin O'Hara, Senior Vice President of Corporate and Community Affairs, recognizing a group of employees for their outstanding service to the Company.

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

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

American Stock Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038
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.

The Company's Chairman, President and Chief Executive Officer certified to the NYSE on April 4, 2008, that as of that date, he was not aware of any violation by the Company of the NYSE's corporate governance listing standards. On December 29, 2008, the Company's Chairman, President and Chief Executive Officer and the Company's Senior Vice President and Chief Financial Officer filed and furnished, respectively, with the Securities and Exchange Commission the certificates required by sections 302 and 906 of the Sarbanes-Oxley Act of 2002, without qualifications.

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.



Nashville, Tennessee is one of Piedmont's fastest growing markets.

FINANCIAL INQUIRIES

Anyone seeking financial information should contact:

John B. Sutphin
Manager – Finance and Investor Relations
704-731-4314
john.sutphin@piedmontng.com

MEDIA INQUIRIES

The media should contact:

David L. Trusty
Managing Director – Public Relations
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
704-364-3120

MAILING ADDRESS

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

ON THE WEB

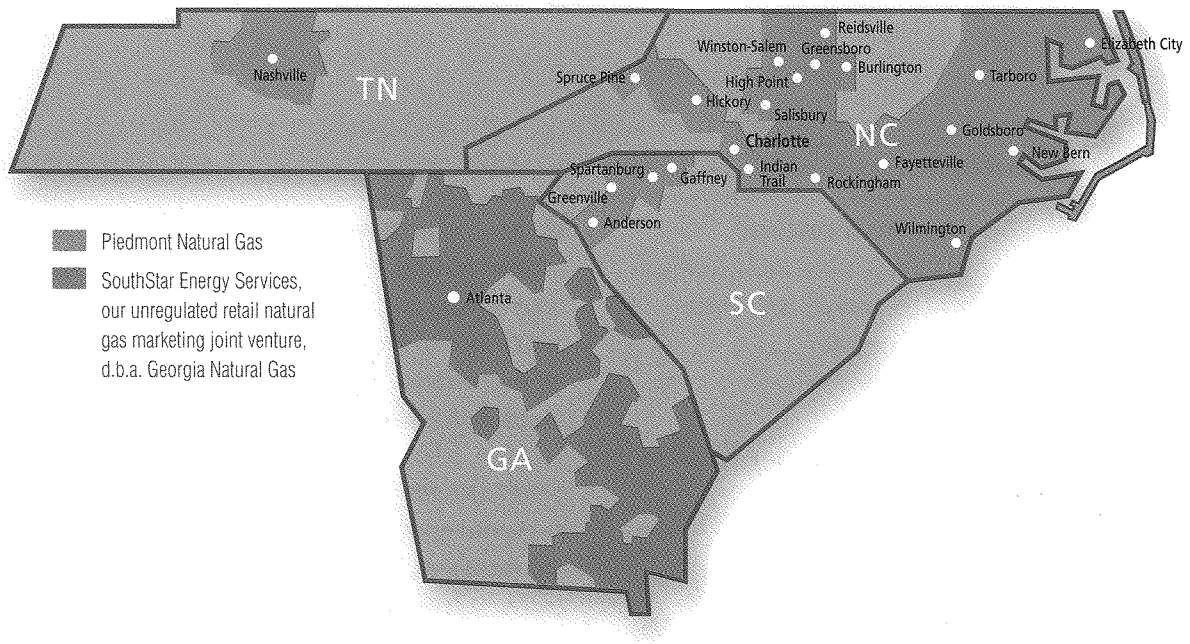
www.piedmontng.com

Piedmont Natural Gas is an Equal Opportunity Employer.

Front cover photo features Doug Wilson, Greensboro Operations Manager, with his daughter, Lillie Margaret and his father, Lynn, a Service Technician in Hickory, NC.

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 62,000 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.



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

Form 10-K

SEC
Mail Processing
Section
FEB 13 2009
Washington, DC
103

(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, 2008

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

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 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. (Check one):

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

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

State the aggregate market value of the voting common equity held by non-affiliates of the registrant as of April 30, 2008.

Common Stock, no par value — $1,911,028,686

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 16, 2008
Common Stock, no par value	73,260,672

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Shareholders on March 6, 2009, are incorporated by reference into Part III.

Piedmont Natural Gas Company, Inc.

2008 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 62,000 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. Operations of our non-utility activities segment are comprised of our equity method investments in joint ventures. Operations of both segments are conducted within the United States of America. For further information on equity method investments and business segments, see Note 10 and Note 11, 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 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, 2008, 39% of our operating revenues were from residential customers, 24% from commercial customers, 12% from large volume customers, including industrial, power generation and resale customers, and 25% from secondary market activities. 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. 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 use and release into the environment of hazardous wastes. 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 the communities we serve, with expiration dates from 2008 to 2058. The franchises are adequate for the operation of our gas distribution business and do not contain materially burdensome restrictions or conditions. Twelve franchise agreements have expired as of

October 31, 2008, and eleven will expire during the 2009 fiscal year. We continue to operate in those areas pursuant to the provisions of the expired franchises with no significant impact on our business. 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 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, 2008, the amount of natural gas in storage varied from 13.2 million dekatherms (one dekatherm equals 1,000,000 BTUs) to 25 million dekatherms, and the aggregate commodity cost of this gas in storage varied from $100.4 million to $190.3 million.

During the year ended October 31, 2008, 121.6 million dekatherms of gas were sold to or transported for large volume customers compared with 122.3 million dekatherms in 2007. Deliveries to temperature-sensitive residential and commercial customers, whose consumption varies with the weather, totaled 88.7 million dekatherms in 2008, compared with 83.7 million dekatherms in 2007. Weather, as measured by degree days, was 5% warmer than normal in 2008 and 12% warmer than normal in 2007.

The following is a five-year comparison of operating statistics for the years ended October 31, 2004 through 2008.

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Sales and Transportation:					
Residential	$ 813,032	$ 743,637	$ 841,051	$ 686,304	$ 624,487
Commercial	503,317	418,426	498,956	421,499	360,355
Industrial	209,341	190,204	205,384	215,505	179,302
For Power Generation	25,266	29,135	22,963	16,248	18,782
For Resale	12,326	13,907	11,342	40,122	38,074
Total	1,563,282	1,395,309	1,579,696	1,379,678	1,221,000
Secondary Market Sales	515,968	308,904	337,278	373,353	301,886
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Total	$2,089,108	$1,711,292	$1,924,628	$1,761,091	$1,529,739
Gas Volumes — Dekatherms (in thousands):					
System Throughput:					
Residential	51,909	50,072	49,119	52,966	54,412
Commercial	36,766	33,647	34,476	36,000	35,483
Industrial	81,780	79,266	80,490	81,102	83,957
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Total	210,251	206,004	198,656	204,438	201,344
Secondary Market Sales	53,442	42,049	40,994	47,057	51,707

	2008	2007	2006	2005	2004
Number of Retail Customers Billed (12-month average):					
Residential	852,586	835,636	815,579	792,061	771,037
Commercial	94,045	93,472	92,692	91,645	90,328
Industrial	2,937	2,959	3,008	3,146	3,194
For Power Generation	20	15	12	16	13
For Resale	17	15	19	15	15
Total	949,605	932,097	911,310	886,883	864,587
Average Per Residential Customer:					
Gas Used — Dekatherms	60.88	59.92	60.23	66.87	70.57
Revenue	$ 953.61	$ 889.90	$ 1,031.23	$ 866.48	$ 809.93
Revenue Per Dekatherm	$ 15.66	$ 14.85	$ 17.12	$ 12.96	$ 11.48
Cost of Gas (in thousands):					
Natural Gas Commodity Costs	$1,454,073	$1,055,600	$1,229,326	$1,226,999	$ 943,890
Capacity Demand Charges	127,640	116,977	99,333	117,287	125,178
Natural Gas Withdrawn From (Injected Into) Storage, net	(78,283)	(12,815)	15,709	(35,151)	(11,116)
Regulatory Charges (Credits), net	32,705	27,365	56,781	(47,183)	(16,582)
Total	$1,536,135	$1,187,127	$1,401,149	$1,261,952	$1,041,370
Supply Available for Distribution (dekatherms in thousands):					
Natural Gas Purchased	159,857	143,598	140,999	155,614	163,257
Transportation Gas	108,332	108,355	101,414	97,959	91,795
Natural Gas Withdrawn From (Injected Into) Storage, net	(2,980)	(1,640)	(197)	856	775
Company Use	(135)	(141)	(127)	(133)	(135)
Total	265,074	250,172	242,089	254,296	255,692

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, 2008, 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 arrangements with East Tennessee and Transco)	38,000
NiSource-Columbia Gas (through arrangements with Transco and Columbia Gulf)	42,800
NiSource-Columbia Gulf	10,000
ONEOK-Midwestern (through arrangements with Tennessee, Columbia Gulf, East Tennessee and Transco)	120,000
Total	917,100

As of October 31, 2008, 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 varying from 5 days to one year.

Piedmont Liquefied Natural Gas (LNG)	278,000
Pine Needle LNG (through arrangements with Transco)	263,400
Williams-Transco Storage	86,100
NiSource-Columbia Gas Storage	96,400
Hardy Storage (through arrangements with Columbia Gas and Transco)	58,700
Dominion Storage (through arrangements with Transco)	13,200
El Paso-Tennessee Pipeline Storage	55,900
Total	851,700

As of October 31, 2008, we own or have under contract 35.3 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 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 are now receiving firm, long-term market area storage service from Hardy Storage Company, LLC, 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.

As 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 a LNG peak storage facility in Robeson County, North Carolina with the capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand. The LNG facility will be a part of our regulated utility segment and is planned to be in service for the 2012-2013 winter heating season. 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, 2008, 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, 2008, no bypass activity was experienced. 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; however, with a tighter national supply and demand balance, wholesale natural gas prices and price volatility have increased in recent years. 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.

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. The relationship between supply and demand has the greatest impact on the price of natural gas. With a tighter balance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market 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. 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, 2008, our largest customer contributed $104.3 million, or 5%, to total operating revenues, which resulted in less than 1% to 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 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, 2008, our fiscal year end, we had 1,833 employees, compared with 1,876 as of October 31, 2007.

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.

Item 1A. *Risk Factors*

Further increases in the wholesale price of natural gas could reduce our earnings and working capital. In recent years, natural gas prices have increased dramatically due to growing demand and limitations on access to domestic gas reserves. The 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. Significant price increases could also cause new home developers 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 significantly higher than historical levels, our working capital costs increase due to carrying higher cost of gas storage inventories, and customers may have trouble paying the resulting higher bills and bad debt expenses may increase and 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, 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.

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. Additionally, Congress has enacted laws that deregulate the price of natural gas sold at the wellhead. 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, that would reduce the availability of supply or capacity, or that would reduce our competitiveness would negatively impact our earnings. Furthermore, Congress has for some time been considering various forms of climate change legislation. There is a possibility that, when and if enacted, the final form of such legislation could impact our costs and put upward pressure on wholesale natural gas prices. Higher cost levels could impact the competitive position of natural gas and negatively affect our growth opportunities, cash flows and 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 50% to 60% of our annual gas sales are to 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. If our rates and tariffs were modified to eliminate weather protection, then we would be exposed to significant risk associated with weather and our earnings could vary as a result.

Governmental 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 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 impacted. Additionally, the 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. Additionally, 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.

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 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 anticipated recovery of these costs of risk management activities is excluded by our regulators in gas cost flow through proceedings.

Operational interruptions to our gas distribution activities caused by accidents, strikes, 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 and mechanical problems. If they 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. Additionally, we have a workforce that is partially represented by the union that exposes us to the risk of a strike. The occurrence of any of these events could adversely affect our financial position, results of operations and cash flows.

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 depends on our credit ratings as well as the liquidity of financial markets. A negative change in our ratings outlook or any downgrade in our current investment-grade credit ratings by our rating agencies could adversely affect our cost and/or access to sources of liquidity and capital. Additionally, such a downgrade could further limit our access to private credit markets and increase the costs of borrowing under available credit lines. 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. 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.

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. Moreover, 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. 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 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 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 include deferring major capital expenditures, changing our gas supply procurement and risk management programs or reducing or eliminating the dividend 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 facilities, 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.

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 or 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.

An overall economic downturn could negatively impact our earnings. The weakening of economic activity in our markets could result in 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 would be affected by these higher costs.

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 27,900 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 private 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.

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 $4.2 million for the year ended October 31, 2008.

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, 2008.

PART II

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

(a) 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, 2008 and 2007.

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
2007	**High**	**Low**
Quarter ended:		
January 31	$28.44	$25.78
April 30	27.50	24.33
July 31	27.50	22.00
October 31	27.50	23.09

(b) As of December 16, 2008, our common stock was owned by 14,993 shareholders of record.

(c) The following table provides information with respect to quarterly dividends paid on common stock for the years ended October 31, 2008 and 2007. We expect that comparable cash dividends will continue to be paid in the future.

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

2007	Dividends Paid Per Share
Quarter ended:	
January 31	24¢
April 30	25¢
July 31	25¢
October 31	25¢

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, 2008, net earnings available for restricted payments were greater than retained earnings; therefore, our retained earnings were not restricted.

The following table provides information with respect to repurchases of our common stock under the Common Stock Open Market Purchase Program during the fourth quarter ended October 31, 2008.

Period	Total Number of Shares Purchased	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 *
Beginning of the period				3,230,074
8/1/08 — 8/31/08 ...	66,000	$28.05	66,000	3,164,074
9/1/08 — 9/30/08 ...	64,000	$29.33	64,000	3,100,074
10/1/08 — 10/31/08 ...	90,000	$30.23	90,000	3,010,074
Total	220,000	$29.32	220,000	

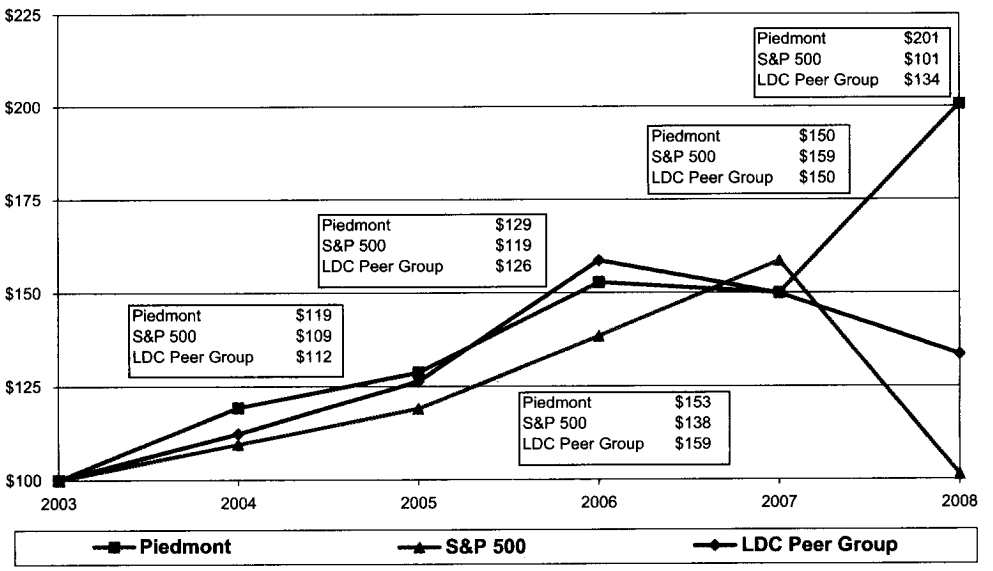
* The Common Stock Open Market Purchase Program was announced on June 4, 2004, to purchase up to three million shares of common stock for reissuance under our dividend reinvestment, stock purchase and incentive compensation plans. On December 16, 2005, the Board of Directors approved an increase in the 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 (ASR) program and have an expiration date of December 31, 2010.

Comparisons of Cumulative Total Shareholder Returns

The following performance graph compares our cumulative total shareholder return from October 31, 2003 through October 31, 2008 (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, 2003, 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, 2003



LDC Peer Group — The following companies are included: AGL Resources, Inc., Atmos Energy Corporation, New Jersey Resources, 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, 2004 through 2008. The information presented for net income and earnings per share for 2004 is not comparable due to the acquisition of the remaining 50% equity interest in Eastern North Carolina Natural Gas Company (EasternNC) effective October 25, 2005. The initial acquisition of 50% of EasternNC was effective September 30, 2003 with the acquisition of North Carolina Natural Gas Corporation.

	2008	2007	2006	2005	2004
	In thousands except per share amounts				
Operating Revenues	$2,089,108	$1,711,292	$1,924,628	$1,761,091	$1,529,739
Margin (operating revenues less cost of gas)	$ 552,973	$ 524,165	$ 523,479	$ 499,139	$ 488,369
Net Income	$ 110,007	$ 104,387	$ 97,189	$ 101,270	$ 95,188
Earnings per Share of Common Stock:					
Basic	$ 1.50	$ 1.41	$ 1.28	$ 1.32	$ 1.28
Diluted	$ 1.49	$ 1.40	$ 1.28	$ 1.32	$ 1.27
Cash Dividends per Share of Common Stock	$ 1.030	$ 0.990	$ 0.950	$ 0.905	$ 0.8525
Total Assets	$3,093,580	$2,820,318	$2,733,939	$2,602,490	$2,392,164
Long-Term Debt (less current maturities)	$ 794,261	$ 824,887	$ 825,000	$ 625,000	$ 660,000

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 Securities and Exchange Commission (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 and industrial growth in our service areas. The ability to grow our customer base and the pace of that growth 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. We must be able to adapt to the changing environments and the competition.
- 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.

- Regulatory issues, customer growth, deregulation, economic and capital market conditions, the cost and availability of natural gas and weather conditions can impact our ability to meet internal performance goals.
- 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 changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost 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 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.
- 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 and system integrity regulations and the cost of compliance. We are subject to extensive federal, state and local regulations. Compliance with such regulations may result in increased capital or operating costs.
- 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 those risks may negatively affect our earnings from those companies.

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 62,000 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 twelve months ended October 31, 2008, 85% 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 further information on business segments, see Note 11 to the consolidated financial statements. For information about our equity method investments, see Note 10 to the consolidated financial statements.

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 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 use and release into the environment of hazardous wastes. 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 will result 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.

We continually assess the nature of our business and explore alternatives in our core business of traditional regulated utility service. Non-traditional ratemaking initiatives and market-based pricing of products and services provide additional opportunities and challenges for us.

We also regularly evaluate opportunities for obtaining natural gas from different supply regions to diversify our natural gas portfolio. In January 2008, we began receiving 120,000 dekatherms per day of firm, long-term transportation service from Midwestern Gas Transmission Company (Midwestern) that provides access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. In April 2007, we began receiving firm, long-term market-area storage service from Hardy Storage Company (Hardy Storage) in West Virginia that will provide 58,700 dekatherms per day of withdrawal service for the winter of 2008-2009. We have a 50% equity interest in this project. For further information, see "Gas Supply and Regulatory Proceedings" below and Note 2, Note 5 and Note 10 to the consolidated financial statements.

As 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 a liquefied natural gas (LNG) peak storage facility in Robeson County, North Carolina with the capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand. The LNG facility will be a part of our regulated utility segment and is planned to be in service for the 2012-2013 winter heating season.

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 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.

While we have seen the impact of the economic recession of 2008 in our market area, we remain one of the fastest growing natural gas utilities in the nation for new customer additions. We added 20,506 new customers to our distribution system in 2008, a gross new customer addition growth rate of 2%. Although we saw a decline in customer growth in our new construction residential market during 2008, we experienced a slight increase in residential customer conversions over 2007. The decline in our customer growth rate did not have a significant effect on our financial results for 2008. As one of the initial investors in the Council for Responsible Energy, we are leading the effort to promote natural gas and inform consumers about the environmental benefits of using natural gas directly in their homes and businesses for the most efficient use of natural gas. In advance of the winter heating season, we work to educate consumers of assistance that is available to those who qualify for the national Low Income Home Energy Assistance Program funds and other similar local programs.

With the recent slowdown in the national economy, including tighter credit markets, increased unemployment and mortgage defaults and significant decreases in investment assets, the financial resources of many domestic households have been adversely affected. A further weakening of the economy in our service areas could result in a greater decline in customer additions and energy consumption which could adversely affect our revenues or restrict our future growth.

Under current economic conditions, it may become more difficult for customers to pay their gas bills, leading to slower collections and higher-than-normal levels of accounts receivable and ultimately increasing the 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.

We remain focused on implementing and improving our underlying business processes while at the same time monitoring economic and other ongoing developments in order to ensure that our operations and business plan stay in step with these developments.

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.

During 2008, margin increased $28.8 million from residential and commercial customer growth as well as period to period net adjustments related to regulatory and gas cost accounting reviews. We were able to realize operations and maintenance expense decreases of $3.7 million primarily due to lower pension expense accruals due to the restructuring of our defined benefit pension program.

Results of Operations

The following tables present our financial highlights for the years ended October 31, 2008, 2007 and 2006.

Income Statement Components

	2008	2007	2006	Percent Change 2008 vs. 2007	Percent Change 2007 vs. 2006
	(In thousands, except per share amounts)				
Operating Revenues	$2,089,108	$1,711,292	$1,924,628	22.1%	(11.1)%
Cost of Gas	1,536,135	1,187,127	1,401,149	29.4%	(15.3)%
Margin	552,973	524,165	523,479	5.5%	0.1%
Operations and Maintenance	210,757	214,442	219,353	(1.7)%	(2.2)%
Depreciation	93,121	88,654	89,696	5.0%	(1.2)%
General Taxes	33,170	32,407	33,138	2.4%	(2.2)%
Income Taxes	62,814	51,315	50,543	22.4%	1.5%
Total Operating Expenses	399,862	386,818	392,730	3.4%	(1.5)%
Operating Income	153,111	137,347	130,749	11.5%	5.0%
Other Income (Expense), net of tax	16,169	24,312	18,750	(33.5)%	29.7%
Utility Interest Charges	59,273	57,272	52,310	3.5%	9.5%
Net Income	$ 110,007	$ 104,387	$ 97,189	5.4%	7.4%
Average Shares of Common Stock:					
Basic	73,334	74,250	75,863	(1.2)%	(2.1)%
Diluted	73,612	74,472	76,156	(1.2)%	(2.2)%
Earnings per Share of Common Stock:					
Basic	$ 1.50	$ 1.41	$ 1.28	6.4%	10.2%
Diluted	$ 1.49	$ 1.40	$ 1.28	6.4%	9.4%

Gas Deliveries, Customers, Weather Statistics and Number of Employees

Deliveries in Dekatherms (in thousands)	2008	2007	2006	Percent Change 2008 vs. 2007	Percent Change 2007 vs. 2006
Sales Volumes	110,801	105,606	105,728	4.9%	(0.1)%
Transportation Volumes	99,450	100,398	92,928	(0.9)%	8.0%
Throughput	210,251	206,004	198,656	2.1%	3.7%
Secondary Market Volumes	53,442	42,049	40,994	27.1%	2.6%
Customers Billed (at period end)	935,724	922,961	903,368	1.4%	2.2%
Gross Customer Additions	20,506	30,437	34,445	(32.6)%	(11.6)%
Degree Days					
Actual	3,195	2,977	3,192	7.3%	(6.7)%
Normal	3,358	3,388	3,386	(0.9)%	0.1%
Percent warmer than normal	(4.9)%	(12.1)%	(5.7)%	n/a	n/a
Number of Employees (at period end)	1,833	1,876	2,051	(2.3)%	(8.5)%

Net Income

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 (operating revenues less cost of gas).
- $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.

Net income increased $7.2 million in 2007 compared with 2006 primarily due to the following changes which increased net income:

- $7.2 million increase in earnings from equity method investments.
- $1.1 million increase in non-operating income.
- $.7 million increase in margin.
- $4.9 million decrease in operations and maintenance expenses, primarily due to organizational restructuring and process improvement initiatives.
- $1 million decrease in depreciation.
- $.7 million decrease in general taxes.

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

- $5 million increase in utility interest charges.
- $3.2 million increase in income taxes.

Operating Revenues

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. 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.
- $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. As discussed in "Financial Condition and Liquidity," the margin decoupling mechanism, previously defined as the Customer Utilization Tracker (CUT) mechanism, in North Carolina adjusts for variations in residential and commercial use per customer including those due to conservation and weather.

Operating revenues in 2007 decreased $213.3 million compared with 2006 primarily due to the following decreases:

- $212.9 million from lower commodity gas costs passed through to customers.
- $28.4 million lower revenues from secondary market transactions.

These decreases were partially offset by the following increases:

- $26.4 million related to non-commodity components in rates.
- $5.2 million from increased volumes delivered to transportation customers.
- $2.3 million from revenues under the WNA in South Carolina and Tennessee.
- $2.3 million from revenues under the CUT in North Carolina.

Cost of Gas

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.

Cost of gas in 2007 decreased $214 million compared with 2006 primarily due to decreases of $212.9 million from lower commodity gas costs passed through to sales customers.

Under PGA procedures 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 66% of

revenues for the twelve months ended October 31, 2008, and transportation and storage costs, which account for 6%.

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 WNA in Tennessee and South Carolina, the Natural Gas Rate Stabilization in South Carolina, secondary market activity in North Carolina and South Carolina, Tennessee Incentive Plan (TIP) in Tennessee, 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 $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.

Margin increased $.7 million in 2007 compared with 2006 primarily due to the following increases:

- $3.9 million from a new power generation customer.
- $4 million net increase, which includes a net increase of 20,800 residential and commercial customers billed (twelve-month average) and an increase of $5.6 million in base rates in South Carolina, partially offset by a decrease in consumption related to warmer-than-normal weather and conservation.

These increases were partially offset by the following decreases:

- $4.6 million, which includes $5.4 million from the regulatory ruling that discontinued the capitalizing and amortizing of storage demand charges, partially offset by $.8 million from 2006 activity.
- $1.9 million from adjustments related to compensating meter indices.
- $1.2 million from adjustments related to the North Carolina 2006 gas cost accounting review.

Operations and Maintenance Expenses

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.

Operations and maintenance expenses decreased $4.9 million in 2007 compared with 2006 primarily due to the following decreases:

- $11 million in payroll primarily related to the management restructuring program in 2006, including impacts on short-term and long-term incentive plan accruals. For further information, see Note 12 to the consolidated financial statements.
- $.6 million in transportation costs primarily due to fewer vehicles being used as a result of our automated meter reading initiative and continuous business process improvements.

These decreases were partially offset by the following increases:

- $3.2 million in outside services primarily due to increased telephony services and our gas accounting, financial close and record retention projects.
- $2 million in employee benefits primarily due to pension and postretirement health care costs and health initiative programs and adjustments in group insurance expense.
- $1.3 million in regulatory expense primarily due to consulting related to gas cost accounting reviews.

Depreciation

Depreciation expense increased from $89.7 million to $93.1 million over the three-year period 2006 to 2008 primarily due to increases in plant in service.

General Taxes

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.

General taxes decreased $.7 million in 2007 compared with 2006 primarily due to the following changes:

- $1.2 million decrease in property taxes related to lower assessments in South Carolina and Tennessee as well as refunds from South Carolina for prior years.
- $.5 million decrease in payroll taxes.
- $.9 million increase in gross receipts taxes in Tennessee.

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 decreased $9.4 million in 2008 compared with 2007 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 Public Service Commission consent agreement related to retail pricing.
- $.9 million increase in earnings from Hardy Storage primarily due to its first full year of operations, partially offset by higher operations and maintenance expenses, depreciation and general taxes.

Income from equity method investments increased $7.2 million in 2007 compared with 2006 due to the following changes:

- $5.3 million increase in earnings from SouthStar primarily due to hedging activities and retail price spreads.
- $2.8 million increase in earnings from Hardy Storage primarily due to storage revenues in 2007 as phase one service to customers began in April 2007.
- $.6 million decrease in earnings from Pine Needle due to reduced rates approved by the FERC in Pine Needle's 2007 rate proceeding.

Utility Interest Charges

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.

Utility interest charges increased $5 million in 2007 compared with 2006 primarily due to the following changes:

- $5.5 million increase in interest on long-term debt due to the issuance on June 20, 2006 of $200 million of insured quarterly notes due June 1, 2036, which was partially offset by the retirement on July 30, 2006 of $35 million of senior notes.
- $.9 million increase in interest expense on regulatory treatment of certain components of deferred income taxes.
- $.9 million increase in interest expense related to a tax audit settlement.
- $2.1 million decrease in interest on short-term debt due to lower balances outstanding in 2007 than in 2006 even though rates were slightly higher in the current period.
- $.4 million decrease in net interest expense on amounts due to/from customers due to higher net receivables in 2007.

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. We access our short-term credit facility to finance our working capital needs and growth. Recent adverse developments in financial and credit markets have made it more difficult and more expensive to access the short-term capital market to meet our liquidity needs. Although the credit markets tightened in the latter half of 2008, we believe that these sources, including amounts available to us under our existing and seasonal facilities, 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, paying down short-term debt, 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 in 2008, 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 mitigate the impact these factors may have on our results of operations.

Net cash provided by operating activities was $69.2 million in 2008, $233.5 million in 2007 and $103.8 million in 2006. Net cash provided by operating activities reflects a $5.6 million increase in net income for 2008, compared with 2007. The effect of changes in working capital on net cash provided by operating activities is described below:

- Trade accounts receivable and unbilled utility revenues increased $12.9 million in the current period primarily due to amounts billed to customers reflecting higher gas costs in 2008 as compared with 2007 and weather in the current period being 7% colder than the same prior period. Volumes sold to residential and commercial customers increased 5 million dekatherms as compared with the same prior period primarily due to the colder weather and customer growth. Total throughput increased 4.2 million dekatherms as compared with the same prior period.

- Net amounts due from customers increased $105.9 million in the current period primarily due to the under-recovery of deferred gas and hedging costs. Included in the amounts due from customers were increased hedging costs from the extension of our hedging transactions over a longer term horizon and the expansion of those transactions to a greater percentage of sales quantities due to lower forward market prices.
- Gas in storage increased $58.8 million in the current period primarily due to a higher average cost of gas in storage as well as increased volumes in storage in 2008 as compared with 2007.
- Prepaid gas costs increased $20.5 million in the current period primarily due to the higher 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 $7.4 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 and fixed and variable non-gas costs and to 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 charges to customers of $6.8 million in 2008, $6.4 million in 2007 and $4.1 million in 2006. 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 a deferred account 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 provided margin of $25.4 million in 2008 and $32.7 million in 2007 and $30.4 million in 2006. 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. With a tighter balance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market 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. 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 by holding down operations and maintenance costs and as part of an ongoing effort aimed at improving business processes, capturing operational and organizational efficiencies and improving customer service, we are continuing the process of standardizing our customer payment and collection processes, streamlining business operations and further consolidating our call centers. These specific initiatives were largely completed during 2008. For further information, see Note 12 to the consolidated financial statements.

Cash Flows from Investing Activities. Net cash used in investing activities was $177.4 million in 2008, $148.2 million in 2007 and $167.6 million in 2006. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures were $181 million in 2008, a 34% increase from the $135.2 million in 2007, primarily due to system infrastructure investments.

We have a substantial capital expansion program for construction of distribution facilities, purchase of equipment and other general improvements. This program primarily supports the growth in our customer base. Gross utility construction expenditures totaling $246.2 million, primarily to serve future customer growth, are budgeted for 2009. We are not contractually obligated to expend capital until the work is completed. Even though we are seeing a slower pace of 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.

As part of our plan to provide safe, reliable gas distribution service to our growing customer base and manage our seasonal demand growth, we intend to design, construct, own and operate a LNG peak storage facility as a regulated utility project in Robeson County, North Carolina with the capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand. The LNG facility is planned to be in service for the 2012-2013 winter heating season. Preliminary estimates place the cost of the facility in the $300 million to $350 million range, with $1.5 million incurred in fiscal year 2008.

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. During 2006, the restrictions on cash totaling $13.2 million were removed in connection with implementing the NCUC order in a general rate proceeding.

In 2008, we contributed $10.9 million 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 18½ 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 2008, we recorded $38,636 of deferred gain.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was $107.7 million in 2008, $(86.6) million in 2007 and $65.6 million in 2006. Funds are primarily provided from bank borrowings and the issuance of common stock through dividend reinvestment and employee stock 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, 2008, our current assets

were $600.8 million and our current liabilities were $681.5 million, primarily due to seasonal requirements as discussed above.

As of October 31, 2008, we had committed lines of credit under our senior credit facility of $450 million with the ability to expand up to $600 million, for which 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 increased from $195.5 million as of October 31, 2007 to $406.5 million as of October 31, 2008, primarily due to higher storage inventory costs, costs associated with the hedging programs, the purchase of shares under the ASR program and payments for interest on short-term debt and property taxes, partially offset by the collections of amounts that had been billed to customers during the winter months. During the twelve months ended October 31, 2008, short-term bank borrowings ranged from $9 million to $426 million, and interest rates ranged from 2.63% to 5.51% (weighted average of 3.79%).

On October 27 and 29, 2008, we entered into two short-term credit facilities with banks for unsecured commitments totaling $75 million expiring on December 1, 2008. On December 1, 2008, these commitments were extended to December 3, 2008. Advances under each short-term facility bear interest at a rate based on the 30-day LIBOR rate plus from .75% to 1.75%, based on our credit ratings. We entered into these short-term facilities to provide lines of credit in addition to the senior revolving credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements, including support for our gas supply procurement program as well as general corporate needs. No borrowings were outstanding at October 31, 2008.

Effective December 3, 2008, we entered into a syndicated seasonal credit facility with aggregate commitments totaling $150 million. Advances under this seasonal facility bear interest at a rate based on the 30-day LIBOR rate plus from .75% to 1.75%, based on our credit ratings. Any borrowings under this agreement are due by March 31, 2009. We entered into this facility to provide lines of credit in addition to the senior revolving credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements and general corporate needs.

As of October 31, 2008, under our senior credit facility, we had available letters of credit of $5 million of which $1.9 million was issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general liability policies. As of October 31, 2008, unused lines of credit available under our credit facilities, including the issuance of the letters of credit, totaled $116.6 million.

The level of short-term bank borrowings can vary significantly due to changes in the wholesale prices of natural gas and to the level of purchases of natural gas supplies and hedging transactions to serve customer demand and for storage. Short-term debt may increase when wholesale prices for natural gas increase because we must pay suppliers for the gas before we collect our costs from customers through their monthly bills. Gas prices could continue to fluctuate. If wholesale gas prices increase, we may incur more short-term debt for natural gas supplies 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.

In September 2009, the balance of $30 million of our 7.35% Medium-Term Notes is due. We anticipate issuing up to $125 million in long-term debt in our 2009 fiscal year for general operating purposes. The timing of this issuance has not yet been determined.

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.

During 2008, we issued $15.6 million of common stock through dividend reinvestment and stock purchase plans. On November 2, 2007, through an ASR agreement, we repurchased and retired 1 million shares of common stock for $24.8 million. On January 15, 2008, we settled the transaction and paid an additional $1.3 million. Under the ASR agreement and the Common Stock Open Market Purchase Program discussed in Note 4 to the consolidated financial statements, we paid $42.7 million during 2008 for 1.6 million shares of common stock that are available for reissuance to these plans. During 2007, 2 million shares were repurchased for $54.2 million. During 2006, 2.1 million shares were repurchased for $50.2 million.

Through the ASR program, we may repurchase and subsequently retire up to approximately four million shares of common stock by no later than December 31, 2010. Through the ASR agreements, we have repurchased 3,850,000 shares as follows.

April 2006	1,000,000
November 2006	1,000,000
March 2007	850,000
November 2007	1,000,000
Total	3,850,000

These shares are in addition to shares that are repurchased on a normal basis through the open market program. During 2009, we do not intend to repurchase any shares under an ASR agreement or the Common Stock Open Market Purchase Program.

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 2008, $.04 per share in 2007 and $.05 per share in 2006. Dividends of $75.5 million, $73.6 million and $72.1 million for 2008, 2007 and 2006, 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, 2008, our retained earnings were not restricted. On December 18, 2008, the Board of Directors declared a quarterly dividend on common stock of $.26 per share, payable January 15, 2009 to shareholders of record at the close of business on December 26, 2008. 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, 2008, our capitalization consisted of 48% in long-term debt and 52% in common equity.

The components of our total debt outstanding (short-term and long-term) to our total capitalization as of October 31, 2008 and 2007 are summarized in the table below.

	October 31		October 31	
	2008	Percentage	2007	Percentage
	In thousands			
Short-term debt	$ 406,500	19%	$ 195,500	10%
Current portion of long-term debt	30,000	1%	—	0%
Long-term debt	794,261	38%	824,887	44%
Total debt	1,230,761	58%	1,020,387	54%
Common stockholders' equity	887,244	42%	878,374	46%
Total capitalization (including short-term debt)	$2,118,005	100%	$1,898,761	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, 2008, 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 bank 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, 2008, we are in compliance with all default provisions.

The default provisions of our senior notes are:

- 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, 2008, our estimated future recorded and unrecorded contractual obligations are as follows.

	Payments Due by Period				
	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
			In thousands		
Recorded contractual obligations					
Long-term debt(1)	$ 30,000	$120,000	$100,000	$574,261	$ 824,261
Short-term debt	406,500	—	—	—	406,500
Total	$436,500	$120,000	$100,000	$574,261	$1,230,761

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

	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
			In thousands		
Unrecorded contractual obligations and commitments(1)					
Pipeline and storage capacity(2)	$148,907	$453,595	$168,998	$335,306	$1,106,806
Gas supply(3)	23,340	369	—	—	23,709
Interest on long-term debt(4)	56,115	149,655	86,917	626,733	919,420
Telecommunications and information technology(5)	18,555	17,106	—	—	35,661
Qualified and nonqualified pension plan funding(6)	11,618	34,714	11,480	—	57,812
Postretirement benefits plan funding(6)	3,400	5,600	1,500	—	10,500
Operating leases(7)	6,232	12,866	7,887	5,956	32,941
Other purchase obligations(8)	32,093	—	—	—	32,093
Letters of credit	2,335	7,005	4,670	—	14,010
FIN 48 obligations	202	305	—	—	507
Total	$302,797	$681,215	$281,452	$967,995	$2,233,459

(1) In accordance with generally accepted accounting principles, 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 7 to the consolidated financial statements.

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

(8) Consists primarily of pipeline products, vehicles, contractors and merchandise.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases and letters of credit discussed in Note 6 and Note 5, respectively, to the consolidated financial statements that are reflected in the table above.

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 and $1.3 million as of October 31, 2008 and 2007, respectively. 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 10 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (Statement 71), 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, 2008 and 2007, totaled $263.2 million and $134 million, respectively. Regulatory liabilities as of October 31, 2008 and 2007, totaled $383.7 million and $374 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, formerly known as the CUT, 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 will result 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 2008, 2007 and 2006 would have been lower by $32.2 million, $39.1 million and $34.6 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 full-time 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 and to modify how benefits are accrued. We also provide certain postretirement health care and life insurance benefits to eligible full-time employees. For further information and our reported costs of providing these benefits, see Note 7 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 6.43% in 2007 to 8.15% in 2008. For the nonqualified pension plans, the weighted average discount rate used in the measurement of the benefit obligation changed from 6.06% in 2007 to 8.46% in 2008. Similarly, based on this approach, the weighted average discount rate for postretirement benefits changed from 6.25% in 2007 to 8.5% in 2008. Based on our review of actual cost trend rates and projected future trends in establishing health care cost trend rates, we maintained the same health care cost trend rate of 8.25% in 2008 and 2007, declining gradually to 5% in 2017.

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 60% equity securities and 40% fixed income securities. The expected long-term rate of return on plan assets was 8.5% in 2006 and 2007, and 8% in 2008. Based on a fairly stagnant inflation trend, our age-related assumed rate of increase in future compensation levels was 4.01% in 2006, decreasing to 3.99% in 2007 and decreasing to 3.97% in 2008 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 2008 Pension Cost	Impact on Projected Benefit Obligation
		Increase (Decrease) In thousands	
Discount rate	(.25)%	$715	$3,023
Rate of return on plan assets	(.25)%	528	N/A
Rate of increase in compensation	.25%	381	1,207

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 2008 Postretirement Benefit Cost	Impact on Accumulated Postretirement Benefit Obligation
		Increase (Decrease) In thousands	
Discount rate	(.25)%	$ 5	$ 511
Rate of return on plan assets	(.25)%	51	N/A
Health care cost trend rate	.25%	21	179

We utilize a number of accounting methods allowed under generally accepted accounting principles (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

We continue to pursue the diversification of 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. In January 2008, we began receiving 120,000 dekatherms per day of firm, long-term transportation contract service from Midwestern that provides access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. In April 2007, we began receiving firm, long-term market-area storage service from Hardy Storage in West Virginia. Hardy Storage will provide us 58,700 dekatherms per day of storage withdrawal service during the winter of 2008-2009, and that service level is planned to increase to 68,800 dekatherms per day for the winter of 2009-2010. We have a 50% equity interest in this project which is more fully discussed in Note 10 to the consolidated financial statements.

As 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 a LNG peak storage facility in Robeson County, North Carolina with the capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand. The LNG facility will be a part of our regulated utility segment and is planned to be in service for the 2012-2013 winter heating season.

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 have been in discussions with FERC's Office of Enforcement (OE) regarding certain instances of possible non-compliance with FERC's capacity release regulations regarding posting and bidding requirements for short-term releases. We have provided relevant information to FERC OE Staff and are cooperating with

FERC in its investigation. We are continuing to meet with FERC's OE staff to resolve this matter. We are unable to predict the outcome of the investigation at this time; however, we do not believe this matter will have a material effect on our earnings.

In October 2008, the NCUC approved a settlement in our general rate case proceeding that provides an annual revenue increase of $15.7 million and the continuation of the margin decoupling mechanism. The new rates become effective November 1, 2008. Also in October 2008, the PSCSC issued an order approving a settlement that provides for an annual decrease of $1.5 million in margin under the Natural Gas Rate Stabilization Act (RSA) mechanism based on a return on equity of 11.2%, effective November 1, 2008. 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 10 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 6 to the consolidated financial statements.

Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements" (Statement 157). Statement 157 provides enhanced guidance 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 Statement 157, 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. Statement 157 clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. Statement 157 establishes a fair value hierarchy for valuation inputs that prioritizes the information used to develop those assumptions into three levels as follows:

- 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.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, through corroboration with observable data.
- Level 3 inputs are unobservable inputs, such as internally developed pricing models for the asset or liability due to little or no market activity for the asset or liability.

Under Statement 157, we anticipate fair value measurements would be disclosed by level for gas purchase options under our gas hedging plans.

In November 2007, the FASB delayed the implementation of Statement 157 for one year only for other nonfinancial assets and liabilities. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis. Accordingly, we will adopt Statement 157 for our fiscal year beginning November 1, 2008 with the exception of the application of the provision related to nonfinancial assets and liabilities. The

adoption of Statement 157 will not have a material impact on our financial position, results of operations or cash flows.

In April 2007, the FASB issued FSP FIN 39-1 to amend paragraph 3 of FIN 39, "Offsetting of Amounts Related to Certain Contracts," to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (Statement 133). The FSP amends paragraph 10 of FIN 39 to permit 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. This FSP 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 amended paragraph 10 of FIN 39 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 will elect "not to net" under FSP FIN 39-1 and will reflect minor reclassifications on our statement of financial position.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" (Statement 141(R)). Statement 141(R) 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. Statement 141(R) 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 Statement 141(R) to any acquisitions we may complete after November 1, 2009.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (Statement 159). Statement 159 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 Statement 159 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. Statement 159 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 Statement 157 early. Accordingly, we will adopt Statement 159 for our fiscal year beginning November 1, 2008. We have evaluated Statement 159, and we do not intend to elect the option to measure any applicable financial assets or liabilities at fair value pursuant to the provisions of Statement 159.

In March 2008, the FASB issued SFAS No. 161, "Disclosures About Derivative Instruments and Hedging Activities" (Statement 161). Statement 161 amends Statement 133, by requiring expanded qualitative, quantitative and credit-risk disclosures about derivative instruments and hedging activities, but does not change the scope or accounting under Statement 133 and its related interpretations. Statement 161 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. Statement 161 also amended SFAS 107, "Disclosures about Fair Value of Financial Instruments" (Statement 107), to clarify that derivative instruments are subject to Statement 107's concentration-of-credit-risk disclosures. Statement 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early adoption permitted. Since Statement 161 only requires additional disclosures concerning derivatives and hedging activities, this standard is not expected to have a material impact on our financial position, results of operations, or cash flows. We will adopt Statement 161 on February 1, 2009.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" (Statement 162). Statement 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements that are presented in conformity

with GAAP for nongovernmental entities. Statement 162 was issued to include the GAAP hierarchy in the accounting literature established by the FASB. Statement 162 will be effective sixty days following the Securities and Exchange Commission (SEC) approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles." We do not expect this statement to have any impact on our financial position, results of operations or cash flows. We will adopt Statement 162 when it becomes effective.

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. 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 any 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, 2008, 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, 2008, we had $406.5 million of short-term debt outstanding under our credit facility at a weighted average interest rate of 2.84%. 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 $1.9 million during 2008.

As of October 31, 2008, information about our long-term debt is presented below.

	Expected Maturity Date							Fair Value as of October 31, 2008
	2009	2010	2011	2012	2013	Thereafter	Total	
	In millions							
Fixed Rate Long-term Debt. . .	$ 30	$ 60	$ 60	$—	$—	$674.3	$824.3	$798.1
Average Interest Rate	7.35%	7.80%	6.55%	—	—	6.64%	6.72%	

Commodity Price Risk

We have mitigated the cash flow risk resulting from commodity purchase contracts under our gas cost recovery mechanisms that permit the recovery of these costs in a timely manner. We face regulatory recovery risk associated with the purchase of natural gas. 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 the New York Mercantile Exchange (NYMEX) exchange-traded 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 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 partially offset the impact of colder-than-normal or warmer-than-normal weather. In North Carolina, we manage our weather risk through a margin decoupling mechanism that allows us to recover our approved margin 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.

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, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2008, 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, 2008, 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 29, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 29, 2008

Piedmont Natural Gas Company, Inc.

Consolidated Balance Sheets
October 31, 2008 and 2007

	2008	2007
	In thousands	
ASSETS		
Utility Plant:		
Utility plant in service	$2,997,186	$2,833,286
Less accumulated depreciation	813,822	752,977
Utility plant in service, net	2,183,364	2,080,309
Construction work in progress	57,470	61,228
Total utility plant, net	2,240,834	2,141,537
Other Physical Property, at cost (net of accumulated depreciation of $2,351 in 2008 and $2,197 in 2007)	864	1,007
Current Assets:		
Cash and cash equivalents	6,991	7,515
Restricted cash	—	2,211
Trade accounts receivable (less allowance for doubtful accounts of $1,066 in 2008 and $544 in 2007)	82,346	97,625
Income taxes receivable	731	15,699
Other receivables	393	649
Unbilled utility revenues	51,819	24,121
Inventories:		
Gas in storage	190,275	131,439
Materials, supplies and merchandise	6,525	5,222
Gas purchase options, at fair value	—	13,725
Amounts due from customers	181,745	76,035
Prepayments	79,831	61,007
Other	96	96
Total current assets	600,752	435,344
Investments, Deferred Charges and Other Assets:		
Equity method investments in non-utility activities	99,214	95,193
Goodwill	48,852	48,852
Overfunded postretirement asset	6,797	36,256
Regulatory asset for postretirement benefits	28,732	1,865
Gas purchase options, at fair value	10,257	—
Unamortized debt expense	9,915	10,565
Regulatory cost of removal asset	6,398	11,939
Other	40,965	37,760
Total investments, deferred charges and other assets	251,130	242,430
Total	$3,093,580	$2,820,318
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Stockholders' equity:		
Cumulative preferred stock — no par value — 175 shares authorized	$ —	$ —
Common stock — no par value — shares authorized: 200,000; shares outstanding: 73,246 in 2008 and 74,208 in 2007	471,565	497,570
Paid-in capital	763	402
Retained earnings	414,246	379,682
Accumulated other comprehensive income	670	720
Total stockholders' equity	887,244	878,374
Long-term debt	794,261	824,887
Total capitalization	1,681,505	1,703,261
Current Liabilities:		
Current maturities of long-term debt	30,000	—
Notes payable	406,500	195,500
Trade accounts payable	91,142	97,156
Other accounts payable	45,148	46,411
Income taxes accrued	4,414	1,224
Accrued interest	22,777	21,811
Customers' deposits	23,881	22,930
Deferred income taxes	6,878	16,422
General taxes accrued	18,932	18,980
Gas purchase options, at fair value	19,561	—
Amounts due to customers	—	162
Other	12,300	3,915
Total current liabilities	681,533	424,511
Deferred Credits and Other Liabilities:		
Deferred income taxes	305,362	267,479
Unamortized federal investment tax credits	2,626	2,983
Regulatory liability for postretirement benefits	372	13,876
Accumulated provision for postretirement benefits	16,257	17,469
Cost of removal obligations	367,450	351,738
Other	38,475	39,001
Total deferred credits and other liabilities	730,542	692,546
Commitments and Contingencies (Note 6)	—	—
Total	$3,093,580	$2,820,318

See notes to consolidated financial statements.

Piedmont Natural Gas Company, Inc.

Consolidated Statements of Income
For the Years Ended October 31, 2008, 2007 and 2006

	2008	2007	2006
	In thousands except per share amounts		
Operating Revenues	$2,089,108	$1,711,292	$1,924,628
Cost of Gas	1,536,135	1,187,127	1,401,149
Margin	552,973	524,165	523,479
Operating Expenses:			
Operations and maintenance	210,757	214,442	219,353
Depreciation	93,121	88,654	89,696
General taxes	33,170	32,407	33,138
Income taxes	62,814	51,315	50,543
Total operating expenses	399,862	386,818	392,730
Operating Income	153,111	137,347	130,749
Other Income (Expense):			
Income from equity method investments	27,718	37,156	29,917
Non-operating income	1,320	2,218	1,147
Charitable contributions	(1,327)	(587)	(321)
Non-operating expense	(864)	(164)	(106)
Income taxes	(10,678)	(14,311)	(11,887)
Total other income (expense), net of tax	16,169	24,312	18,750
Utility Interest Charges:			
Interest on long-term debt	55,449	55,440	49,915
Allowance for borrowed funds used during construction	(4,002)	(3,799)	(3,893)
Other	7,826	5,631	6,288
Total utility interest charges	59,273	57,272	52,310
Net Income	$ 110,007	$ 104,387	$ 97,189
Average Shares of Common Stock:			
Basic	73,334	74,250	75,863
Diluted	73,612	74,472	76,156
Earnings Per Share of Common Stock:			
Basic	$ 1.50	$ 1.41	$ 1.28
Diluted	$ 1.49	$ 1.40	$ 1.28

See notes to consolidated financial statements.

Piedmont Natural Gas Company, Inc.

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2008, 2007 and 2006

	2008	2007	2006
		In thousands	
Cash Flows from Operating Activities:			
Net income	$ 110,007	$ 104,387	$ 97,189
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	97,637	93,355	94,111
Amortization of investment tax credits	(358)	(434)	(534)
Allowance for doubtful accounts	522	(695)	51
Gain on sale of land	(711)	—	—
Allowance for funds used during construction	—	—	(3,893)
Income from equity method investments	(27,718)	(37,156)	(29,917)
Distributions of earnings from equity method investments	34,060	27,884	28,442
Deferred income taxes	28,370	23,854	22,021
Stock-based compensation expense	338	336	—
Changes in assets and liabilities:			
Receivables	(12,685)	14,892	19,395
Inventories	(60,139)	7,743	12,791
Amounts due from customers	(105,710)	13,599	(37,474)
Settlement of legal asset retirement obligations	(1,358)	(1,660)	—
Overfunded postretirement asset	29,459	(36,256)	—
Regulatory asset for postretirement benefits	(26,867)	(1,786)	—
Other assets	(5,469)	(351)	7,581
Accounts payable	(8,617)	13,069	(94,095)
Amounts due to customers	(162)	39	(17,001)
Regulatory liability for postretirement benefits	(13,504)	13,876	—
Accumulated provision for postretirement benefits	(1,212)	17,469	—
Other liabilities	33,319	(18,664)	5,146
Total adjustments	(40,805)	129,114	6,624
Net cash provided by operating activities	69,202	233,501	103,813
Cash Flows from Investing Activities:			
Utility construction expenditures	(181,001)	(135,231)	(204,116)
Allowance for funds used during construction	(4,002)	(3,799)	—
Reimbursements from bond fund	—	—	15,955
Contributions to equity method investments	(10,917)	(12,914)	(23,696)
Distributions of capital from equity method investments	98	344	28,968
Proceeds from sale of land and buildings	13,159	—	—
Decrease (increase) in restricted cash	2,196	(2,211)	13,108
Other	3,090	5,576	2,227
Net cash used in investing activities	(177,377)	(148,235)	(167,554)
Cash Flows from Financing Activities:			
Increase in notes payable, net of expenses of $405 in 2006	211,000	25,500	11,095
Proceeds from issuance of long-term debt, net of expenses	—	—	193,360
Retirement of long-term debt	(626)	(113)	(35,000)
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	15,591	15,782	18,377
Repurchases of common stock	(42,678)	(54,240)	(50,163)
Dividends paid	(75,513)	(73,561)	(72,107)
Net cash provided by (used in) financing activities	107,651	(86,637)	65,562
Net Increase (Decrease) in Cash and Cash Equivalents	(524)	(1,371)	1,821
Cash and Cash Equivalents at Beginning of Year	7,515	8,886	7,065
Cash and Cash Equivalents at End of Year	$ 6,991	$ 7,515	$ 8,886
Cash Paid During the Year for:			
Interest	$ 63,769	$ 63,703	$ 54,669
Income taxes	29,281	27,423	56,615
Noncash Investing and Financing Activities:			
Accrued construction expenditures	$ 1,340	$ 741	$ 2,837
Guaranty	101	485	1,820

See notes to consolidated financial statements.

Piedmont Natural Gas Company, Inc.

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2008, 2007 and 2006

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	In thousands except per share amounts				
Balance, October 31, 2005	$562,880	$ —	$323,565	$(2,253)	$884,192
Comprehensive Income:					
Net income			97,189		97,189
Other comprehensive income:					
Minimum pension liability, net of tax of ($51)				(78)	
Unrealized gain from hedging activities of equity method investments, net of tax of $3,013				4,644	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($665)				(973)	3,593
Total comprehensive income					100,782
Common Stock Issued	20,047				20,047
Common Stock Repurchased	(50,163)				(50,163)
Share-Based Compensation Expense		56			56
Tax Benefit from Dividends Paid on ESOP Shares			118		118
Dividends Declared ($.95 per share)			(72,107)		(72,107)
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	
Unrealized gain from hedging activities of equity method investments, net of tax of $314				578	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($762)				(1,276)	(674)
Total comprehensive income					103,713
Adjustment to initially apply Statement 158, net of tax				54	54
Common Stock Issued	19,046				19,046
Common Stock Repurchased	(54,240)				(54,240)
Share-Based Compensation Expense		336			336
Dividends — Incentive Compensation Plan		10	(10)		—
Tax Benefit from Dividends Paid on ESOP Shares			101		101
Dividends Declared ($.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	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($922)				(1,449)	(50)
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

The components of accumulated other comprehensive income (OCI) as of October 31, 2008 and 2007 are as follows.

	2008	2007
	In thousands	
Hedging activities of equity method investments	$670	$720

See 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 10 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting For The Effects of Certain Types of Regulation" (Statement 71).

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. Statement 71 provides 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 Statement 71, 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 the provisions of Statement 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income. Although the natural gas distribution industry is becoming increasingly competitive, 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 Statement 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and 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, 2008 and 2007 are as follows.

	2008	2007
	In thousands	
Regulatory Assets:		
Unamortized debt expense	$ 9,915	$ 10,565
Amounts due from customers	181,745	76,035
Environmental costs*	5,819	4,223
Demand-side management costs*	1,608	2,631
Deferred operations and maintenance expenses*	9,301	9,286
Deferred pipeline integrity expenses*	6,008	4,417
Deferred pension and other retirement benefits costs*	12,558	11,146
FAS 158 pension and other retirement benefits costs*	28,732	1,865
Regulatory cost of removal asset	6,398	11,939
Other*	1,121	1,866
Total	$263,205	$133,973
Regulatory Liabilities:		
Regulatory cost of removal obligations	$359,302	$334,079
Amounts due to customers	—	162
Deferred income taxes	24,316	25,463
FAS 158 pension and other retirement benefits costs	66	13,876
Environmental liability due customers*	—	386
Total	$383,684	$373,966

* Regulatory assets are included in "Other" in "Investments, Deferred Charges and Other Assets" and regulatory liabilities are included in "Other" in "Deferred Credits and Other Liabilities" in the consolidated balance sheets.

As of October 31, 2008, we had regulatory assets totaling $6.2 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, $.1 million will be fully amortized by 2010, $5.4 million will be fully amortized by 2011 and the remaining $.7 million will be fully amortized by 2018. We have $55.9 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 $28.7 million of regulatory postretirement assets and $6.4 million of asset retirement obligations 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, 2008, 2007 and 2006 is presented below.

	October 31		
	2008	2007	2006
	In thousands		
AFUDC	$4,002	$3,799	$3,893

We compute depreciation expense using the straight-line method over periods ranging from four to 88 years. The composite weighted-average depreciation rates were 3.23% for 2008, 3.23% for 2007 and 3.46% for 2006.

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 rates.

D. Asset Retirement Obligations.

SFAS No. 143, "Accounting for Asset Retirement Obligations" (AROs) (Statement 143), 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 asset. Statement 143 requires the recognition of the fair value of a liability for an ARO 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 Statement 143. Because these estimated removal costs meet the requirements of Statement 71, 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 "Deferred Credits and Other 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 Financial Accounting Standards Board (FASB) Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), that requires recognition of a liability for the fair value of a conditional ARO when incurred if the liability can be reasonably estimated. An ARO will be capitalized concurrently by increasing the carrying amount of the related asset by the same amount of 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 the conditional ARO must be recognized. 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, 2008 and 2007 are shown below.

	2008	2007
	In thousands	
Regulatory non-legal asset removal obligations	$359,302	$334,079
Conditional asset retirement obligations	8,148	17,659
Total cost of removal obligations	$367,450	$351,738

A reconciliation of the changes in the FIN 47 conditional ARO for the year ended October 31, 2008 and 2007 is presented below.

	2008	2007
	In thousands	
Beginning of period	$ 17,659	$19,115
Liabilities incurred during the period	2,004	2,564
Liabilities settled during the period	(1,358)	(1,660)
Accretion	1,104	1,102
Adjustment to estimated cash flows*	(11,261)	(3,462)
End of period	$ 8,148	$17,659

* Adjustment is primarily due to the change in the credit adjusted risk-free rate from 5.78% as of October 31, 2006 to 6.24% as of October 31, 2007 to 8.62% as of October 31, 2008.

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), the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA), we are authorized to recover all uncollected gas costs through the gas cost deferral account. 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. Merchandise receivables due beyond one year are included in "Other" in "Investments, Deferred Charges and Other Assets" in the consolidated balance sheets.

A reconciliation of changes in the allowance for doubtful accounts for the years ended October 31, 2008, 2007 and 2006 is as follows.

	2008	2007	2006
		(In thousands)	
Balance at beginning of year	$ 544	$ 1,239	$ 1,188
Additions charged to uncollectibles expense	5,308	4,981	4,706
Accounts written off, net of recoveries	(4,786)	(5,676)	(4,655)
Balance at end of year	$ 1,066	$ 544	$ 1,239

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

All of our goodwill is attributable to the regulated utility segment. We evaluate goodwill for impairment annually 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, 2008, 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, 2008, 2007 and 2006.

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, 2008, 2007 and 2006 that resulted in any impairment charges. For further information on equity method investments, see Note 10 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. We amortize 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.

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, 2008, such counterparties held natural gas storage assets, included in "Prepayments" in the consolidated balance sheets, with a value of $77.4 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 April 30, 2009.

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 purchased gas adjustment (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. 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 in accordance with SFAS No. 109, "Accounting for Income Taxes," and FASB Interpretation 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). Deferred taxes are primarily attributable to utility plant, equity method investments and revenues and cost of gas. 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 pursuant to Statement 71, 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 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.

K. 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.J to the consolidated financial statements.

L. Earnings Per Share.

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. A reconciliation of basic and diluted earnings per share for the years ended October 31, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
	In thousands except per share amounts		
Net Income	$110,007	$104,387	$97,189
Average shares of common stock outstanding for basic earnings per share	73,334	74,250	75,863
Contingently issuable shares under the Executive Long-Term Incentive Plan and Incentive Compensation Plan	278	222	293
Average shares of dilutive stock	73,612	74,472	76,156
Earnings Per Share:			
Basic	$ 1.50	$ 1.41	$ 1.28
Diluted	$ 1.49	$ 1.40	$ 1.28

M. 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.

N. 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.

O. Recently Issued Accounting Standards.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements" (Statement 157). Statement 157 provides enhanced guidance 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 Statement 157, 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. Statement 157 clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. Statement 157 establishes a fair value hierarchy for valuation inputs that prioritizes the information used to develop those assumptions into three levels as follows:

- 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.
- Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, through corroboration with observable data.
- Level 3 inputs are unobservable inputs, such as internally developed pricing models for the asset or liability due to little or no market activity for the asset or liability.

Under Statement 157, we anticipate fair value measurements would be disclosed by level for gas purchase options under our gas hedging plans.

In November 2007, the FASB delayed the implementation of Statement 157 for one year only for other nonfinancial assets and liabilities. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis. Accordingly, we will adopt Statement 157 for our fiscal year beginning November 1, 2008 with the exception of the application of the provision related to nonfinancial assets and liabilities. The adoption of Statement 157 will not have a material impact on our financial position, results of operations or cash flows.

In April 2007, the FASB issued FSP FIN 39-1 to amend paragraph 3 of FIN 39, "Offsetting of Amounts Related to Certain Contracts," to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (Statement 133). The FSP amends paragraph 10 of FIN 39 to permit 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. This FSP 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 amended paragraph 10 of FIN 39 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 will elect "not to net" under FSP FIN 39-1 and will reflect minor reclassifications on our statement of financial position.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" (Statement 141(R)). Statement 141(R) 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. Statement 141(R) 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 Statement 141(R) to any acquisitions we may complete after November 1, 2009.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (Statement 159). Statement 159 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 Statement 159 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. Statement 159 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 Statement 157 early. Accordingly, we will adopt Statement 159 for our fiscal year beginning November 1, 2008. We have evaluated Statement 159, and we do not intend to elect the option to measure any applicable financial assets or liabilities at fair value pursuant to the provisions of Statement 159.

In March 2008, the FASB issued SFAS No. 161, "Disclosures About Derivative Instruments and Hedging Activities" (Statement 161). Statement 161 amends Statement 133, by requiring expanded qualitative, quantitative and credit-risk disclosures about derivative instruments and hedging activities, but does not change the scope or accounting under Statement 133 and its related interpretations. Statement 161 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. Statement 161 also amended SFAS 107, "Disclosures about Fair Value of Financial Instruments" (Statement 107), to clarify that derivative instruments are subject to Statement 107's concentration-of-credit-risk disclosures. Statement 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early adoption permitted. Since Statement 161 only requires additional disclosures concerning derivatives and hedging activities, this standard is not expected to have a material impact on our financial position, results of operations, or cash flows. We will adopt Statement 161 on February 1, 2009.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" (Statement 162). Statement 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements that are presented in conformity with GAAP for nongovernmental entities. Statement 162 was issued to include the GAAP hierarchy in the accounting literature established by the FASB. Statement 162 will be effective sixty days following the Securities and Exchange Commission (SEC) approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles." We do not expect this statement to have any impact on our financial position, results of operations or cash flows. We will adopt Statement 162 when it becomes effective.

2. Regulatory Matters

Our utility operations are regulated by the NCUC, PSCSC and 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 April 2005, we filed a general rate case with the NCUC requesting a consolidation of the respective rate bases, revenues and expenses of Piedmont, North Carolina Natural Gas Corporation (NCNG) and Eastern North Carolina Natural Gas Company (EasternNC). In addition to a unified and uniform rate structure for all customers served by us in North Carolina, the application requested a general restructuring and increase in rates and charges for customers to produce an overall annual increase in margin of $36.7 million, a consolidation and/or amortization of certain deferred accounts, changes to cost allocations and rate design including a tariff mechanism that decouples margin recovery from residential and commercial customer consumption, changes and unification of existing service regulations and tariffs, common depreciation rates for plant and recovery of uncollectible gas costs through the gas cost deferred account.

In November 2005, the NCUC issued an order in this general rate case proceeding establishing a margin decoupling mechanism that provides for the recovery of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism was experimental for a three-year period, subject to review and approval for extension in a future general rate case proceeding. The margin decoupling mechanism, which replaced our WNA mechanism that adjusted margins for weather, has been operating for three years and reconciles our margin earned each month. We file for semi-annual rate adjustments to refund any over-collection of margin or recover any under-collection of margin. Each of these rate adjustments has been approved by the NCUC.

Under the NCUC's orders and the terms of a settlement with the North Carolina Attorney General for the three years of the experimental margin decoupling program, we allocated $500,000 to energy conservation program funding and shared the first $3 million of the margin adjustment that was non-weather related. Annually, the first $3 million of non-weather related amounts will be allocated 25% to customer rate reduction, 25% to energy conservation program funding and 50% to us. Since the inception of the program on November 1, 2005, we have incurred charges of $6.3 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 $.3 million

for interest accruals on the conservation funding and reduction of customer rates. The conservation programs are subject to review and approval by the NCUC. At October 31, 2008 and 2007, we had liabilities for the conservation programs of $1.3 million and $1.5 million, respectively.

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. In addition to the revenue increase, the stipulation also includes 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 the existing service regulations and tariffs. The new rates became effective November 1, 2008.

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 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. 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.

In October 2004, we filed a petition with the NCUC seeking deferred accounting treatment for certain pipeline integrity management costs to be incurred by us 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 discussed above, the balance of $.4 million in the deferred account as of June 30, 2005, is being amortized over three years beginning November 1, 2005, and subsequent expenditures that total $4.3 million as of October 31, 2007 will continue to be 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 subject to amortization 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, 2008 that is not being amortized that is subject to a future rate proceeding is $1.4 million.

On February 16, 2005, the Natural Gas Rate Stabilization Act (RSA) of 2005 became effective 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 Act, the annual filing will provide that the utility's rate of return on equity will remain within a 50-basis points band above or below the current allowed rate of return on equity. In April 2005, we filed an election with the PSCSC to adopt this new mechanism.

In June 2006, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2006, along with revenue deficiency calculations and proposed changes in our tariff rates. In the filing, we requested an increase in annual margin of $10.3 million. In September 2006, we, the Office of Regulatory Staff (ORS) and the South Carolina Energy Users Committee (SCEUC) filed a settlement agreement with the PSCSC addressing our proposed rate changes under the RSA. In September 2006, the PSCSC issued an order approving a $5.6 million increase in margin based on 11.2% return on equity effective November 1, 2006.

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 ORS and the 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.

All three jurisdictions regulate our gas purchasing practices under a standard of prudence and audit our gas cost accounting practices. As part of this jurisdictional oversight, all three states address our gas supply hedging activities. Additionally, as detailed below, all three states allow for recovery of uncollectible gas costs through the PGA.

In North Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. We have been found prudent in all past proceedings.

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 August 2008, we filed testimony in North Carolina in support of our gas cost purchasing and accounting practices for the period ending May 31, 2008. A hearing was held on December 16, 2008. We are unable to determine the outcome of the proceeding at this time.

Our gas cost hedging plan for North Carolina is designed for the purpose of cost stabilization and targets 30% to 60% 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 August 2007 gas cost review order and our November 2007 gas cost review order found our hedging activities during the two review periods to be reasonable and prudent.

Since November 1, 2005, the NCUC has allowed the recovery of all uncollectible gas costs through the gas cost PGA deferral account. As a result, 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 South Carolina, our recovery of gas costs is subject to annual gas cost proceedings to determine the prudence of our gas purchases. We have been found prudent in all past proceedings.

In South Carolina, the PSCSC approved a settlement in August 2006 between us, the ORS and the SCEUC accepting our purchased gas adjustments and finding our gas purchasing policies prudent for the twelve months ended March 31, 2006. As part of this settlement, we began recovering uncollectible gas costs through the PGA effective November 1, 2006. In May 2008, the PSCSC approved our purchased gas adjustments and found our gas purchasing policies prudent for the twelve months ended March 31, 2007.

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

The PSCSC has approved a gas cost hedging plan for the purpose of cost stabilization for South Carolina customers. The plan targets 30% to 60% 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 Tennessee, the Tennessee Incentive Plan (TIP) replaced annual prudence reviews under the Actual Cost Adjustment (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. The costs and benefits of hedging instruments and all other gas costs incurred are components of the TIP. 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, maintain the current $1.6 million annual incentive cap on gains and losses, improve the transparency of plan operations by an agreed to request for proposal procedures for asset management transactions and provide for a triennial review of TIP operations by an independent consultant.

We have filed an annual report for the twelve months ended December 31, 2006 with the TRA that reflects 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 includes cost of gas adjustments for the calendar year 2006 review period. There was no material impact from these gas cost adjustments.

In March 2003, we, along with two other natural gas companies in Tennessee, filed a petition with the TRA requesting a declaratory order that the gas cost portion of uncollectible accounts be recovered through PGA procedures. We requested that 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. With TRA approval, this methodology was used on an experimental basis for two years. In August 2006, the TRA approved the methodology permanently.

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.

We filed petitions with the NCUC, the PSCSC and the TRA in September 2006 for authorization to place certain ARO costs in deferred accounts so that the regulatory treatment for these costs will not be altered due to our adoption of FIN 47. The petitions were approved in all of the jurisdictions in November 2007, effective October 31, 2006.

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 SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (Statement 158) 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, 2008 and 2007 is as follows.

	2008	2007
	In thousands	
Senior Notes:		
8.51%, due 2017	$ 35,000	$ 35,000
Medium-Term Notes:		
7.35%, due 2009	30,000	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	199,261	199,887
Total	824,261	824,887
Less current maturities	30,000	—
Total	$794,261	$824,887

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

	In thousands
2009	$ 30,000
2010	60,000
2011	60,000
2012	—
2013	—
Thereafter	674,261
Total	$824,261

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 was $109.4 million.

Payments of $.6 million and $.1 million in 2008 and 2007, 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.

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, 2008, our retained earnings were not restricted because the amount available for restricted payments was greater than our actual retained earnings as of this date as presented below.

	In thousands
Amount available for restricted payments	$538,383
Retained earnings	414,246

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, 2008, we are in compliance with all default provisions.

4. Capital Stock and Accelerated Share Repurchase

Changes in common stock for the years ended October 31, 2006, 2007 and 2008 are as follows.

	Shares	Amount
	In thousands	
Balance, October 31, 2005	76,698	$562,880
Issued to participants in the Employee Stock Purchase Plan (ESPP)	36	882
Issued to the Dividend Reinvestment and Stock Purchase Plan (DRIP)	735	17,496
Issued to participants in the Executive Long-Term Incentive Plan (LTIP)	75	1,669
Shares repurchased under Common Stock Open Market Repurchase Plan	(1,080)	(25,871)
Shares repurchased under Accelerated Share Repurchase (ASR) Plan	(1,000)	(24,292)
Balance, October 31, 2006	75,464	532,764
Issued to ESPP	34	809
Issued to DRIP	593	14,973
Issued to LTIP	117	3,264
Shares repurchased under Common Stock Open Market Repurchase Plan	(150)	(3,953)
Shares repurchased under 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

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 under the ESPP, DRIP and LTIP.

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 are referred to as our ASR program and have an expiration date of December 31, 2010.

On November 1, 2007, we entered into an ASR agreement. On November 2, 2007, we purchased and retired 1 million shares of our common stock from an investment bank at the closing price that day of $24.70 per share. Total consideration paid to purchase the shares of $24.8 million, including $92,500 in commissions and other fees, 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 60 trading days. Under the terms of the forward sale contract, the investment bank was required to purchase, in the open market, 1 million 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 November 2, 2007 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 November 2, 2007 closing price. At settlement on January 15, 2008, we paid cash of $1.3 million to the investment bank and recorded this amount in "Stockholders' equity" as a reduction in "Common stock" in the consolidated balance sheets. The $1.3 million was the difference between the investment bank's weighted average purchase price of $26.0459 and the November 2, 2007 closing price of $24.70 per share multiplied by 1 million shares.

As of October 31, 2008, 2.9 million shares of common stock were reserved for issuance as follows.

	In thousands
ESPP	75
DRIP	329
LTIP and ICP	2,490
Total	2,894

5. Financial Instruments and Related Fair Value

On January 16, 2008, we increased the aggregate commitments under our syndicated five-year revolving credit facility from $350 million to $450 million to meet working capital requirements. 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 $1.9 million and $1.5 million were issued and outstanding at October 31, 2008 and 2007, 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%, based on our credit ratings.

On October 27 and 29, 2008, we entered into two short-term credit facilities with banks for unsecured commitments totaling $75 million expiring on December 1, 2008. On December 1, 2008, these commitments were extended to December 3, 2008. Advances under each short-term facility bear interest at a rate based on the 30-day LIBOR rate plus from .75% to 1.75%, based on our credit ratings. We entered into these short-term facilities to provide lines of credit above the senior revolving credit facility discussed above in order to have additional resources to meet seasonal cash flow requirements, including support for our gas supply

procurement program as well as general corporate needs. No borrowings under these facilities were outstanding at October 31, 2008.

As of October 31, 2008 and 2007, outstanding short-term borrowings under the credit facility as included in "Notes payable" in the consolidated balance sheets were $406.5 million and $195.5 million, respectively, in LIBOR cost-plus loans at a weighted average interest rate of 2.84% in 2008 and 4.96% in 2007. Our 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 58% at October 31, 2008. As of October 31, 2008, the unused committed lines of credit totaled $116.6 million.

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, 2008 and 2007, our trade accounts receivable consisted of the following.

	2008	2007
	In thousands	
Gas receivables	$81,234	$95,918
Merchandise and jobbing receivables	2,178	2,251
Allowance for doubtful accounts	(1,066)	(544)
Trade accounts receivable	$82,346	$97,625

The carrying amounts in the consolidated balance sheets of cash and cash equivalents, restricted cash, receivables, notes payable and accounts payable approximate their fair values due to the short-term nature of these financial instruments. Based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit ratings, the estimated fair value amounts of long-term debt as of October 31, 2008 and 2007, including current portion, were as follows.

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	In thousands			
Long-term debt	$824,261	$798,057	$824,887	$892,506

The use of different market assumptions or estimation methodologies could have a material effect on the estimated fair value amounts. The fair value amounts reflect principal amounts that we will ultimately be required to pay.

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. We structure the pricing, quantity and term provisions of our gas supply contracts to maximize flexibility and minimize cost and risk for our customers. Our risk management policies allow us to use financial instruments to hedge risks, but not for speculative trading. The strategy and objective of our hedging programs is to use these financial instruments to provide increased price stability for our customers. We have a management-level Energy Risk Management Committee that monitors compliance with our risk management policies.

In 2008, we purchased and sold financial options for natural gas for our Tennessee gas supply portfolio. As of October 31, 2008, we had forward positions for December 2008 through March 2010. The costs 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 2008, we purchased and sold financial options for natural gas for our South Carolina gas supply portfolio. As of October 31, 2008, we had forward positions for December 2008 through October 2010. 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 2008, we purchased and sold financial options for natural gas for our North Carolina gas supply portfolio. As of October 31, 2008, we had forward positions for December 2008 through October 2010. Costs associated with our North Carolina 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.

Current period changes in the assets and liabilities from these risk management activities are recorded as a component of gas costs in amounts due to customers or amounts due from customers in accordance with Statement 71. We mark the derivative instruments to market with a corresponding entry to "Amounts due to customers" or "Amounts due from customers" in the consolidated balance sheets. Accordingly, there is no earnings impact of the hedging programs on the regulated utility segment as a result of the use of these financial derivatives. The total fair value of gas purchase options included in the consolidated balance sheets as of October 31, 2008 and 2007 is presented as follows.

	2008	2007
	In thousands	
Current portion — gas purchase options	$(19,561)	$13,725
Non-current portion — gas purchase options	10,257	—
Total	$ (9,304)	$13,725

6. 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, 2008, 2007 and 2006 are as follows.

	2008	2007	2006
		In thousands	
Operating lease payments	$5,483	$6,587	$7,246

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

	In thousands
2009	$ 6,232
2010	4,739
2011	4,098
2012	4,029
2013	3,973
Thereafter	9,870
Total	$32,941

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 fifteen years. The time periods for gas supply contracts range from one to four 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 four 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, 2008, future unconditional purchase obligations for the next five years ending October 31 and thereafter are as follows.

	Pipeline and Storage Capacity	Gas Supply	Telecommunications and Information Technology	Other	Total
			In thousands		
2009	$ 148,907	$23,340	$18,555	$32,093	$ 222,895
2010	152,305	214	10,306	—	162,825
2011	151,210	119	4,598	—	155,927
2012	150,080	36	2,202	—	152,318
2013	97,293	—	—	—	97,293
Thereafter	407,011	—	—	—	407,011
Total	$1,106,806	$23,709	$35,661	$32,093	$1,198,269

Legal

We have only routine immaterial 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 $1.9 million in letters of credit that were issued and outstanding at October 31, 2008. Additional information concerning letters of credit is included in Note 5 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.

Several years ago, 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 an amount, 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, we have revised our estimate of the total cost to remediate the Hickory MGP site to be approximately $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 liquefied natural gas (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. Our estimate of the total cost to remediate these areas is $1.1 million. In accordance with the deferral accounting authorized by our regulatory commissions, we adjusted the regulatory asset and the estimated liability for this additional amount.

As of October 31, 2008, our undiscounted environmental liability totaled $4.1 million, and consisted of $2.5 million for the four MGP sites for which we retain remediation responsibility, $1.1 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 and in 2007 by $.1 million to reflect the impact of inflation based on the consumer price index.

As of October 31, 2008, our regulatory assets for unamortized environmental costs totaled $5.8 million. The portion of the regulatory assets representing actual costs incurred, including the settlement payment to the third party, is being amortized as recovered in rates from customers.

In connection with the 2003 NCNG acquisition, several MGP sites owned by NCNG were transferred to a wholly owned subsidiary of Progress Energy, Inc.'s (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 October 2003, in connection with a 2003 NCNG general rate case proceeding, the NCUC ordered an environmental regulatory liability of $3.5 million be established for refund to customers over the three-year period beginning November 1, 2003. This liability resulted from a payment made to NCNG by its insurers prior to our acquisition of NCNG. As part of the 2005 general rate case proceeding discussed in Note 2 to the consolidated financial statements, the NCUC ordered a new three-year amortization period for the unamortized balance as of June 30, 2005, beginning November 1, 2005. As of October 31, 2008, the liability was completely amortized.

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 non-regulated environmental liabilities 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, cash flows or results of operations.

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 have been in discussions with FERC's Office of Enforcement (OE) regarding certain instances of possible non-compliance with FERC's capacity release regulations regarding posting and bidding requirements for short-term releases. We have provided relevant information to FERC OE Staff and are cooperating with FERC in its investigation. We are continuing to meet with FERC's OE staff to resolve this matter. We are unable to predict the outcome of the investigation at this time; however, we do not believe this matter will have a material effect on our earnings.

7. Employee Benefit Plans

Effective January 1, 2008, we amended our noncontributory defined benefit pension plan, other postretirement employee benefits (OPEB) plan and our defined contribution plans. These amendments apply to nonunion employees and employees covered by the Carolinas bargaining unit contract. Effective January 1, 2009, these amendments will apply 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 full-time 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 will continue to participate in the amended traditional defined benefit pension plan. The amendment does not affect any pension benefit earned as of December 31, 2007. For service earned after December 31, 2007, a consistent rate will be applied to each year of service so that employees accrue benefits more evenly. For service earned prior to January 1, 2008, the rate used in the formula to calculate an employee's pension benefit is greater for the first twenty years of service than it is for the next fifteen years of service. Employees 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 will be 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) will not participate in the amended traditional pension plan but will be participants in the new Money Purchase Pension (MPP) plan, a defined contribution pension plan that allows the employee to direct the investments. Full-time employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Under the MPP plan, we will annually deposit a percentage of each participant's pay into an account of the MPP plan. This contribution will be equal to 4% of the participant's compensation plus an additional 4% of compensation above the social security wage base. The participant becomes vested in this plan after three years of service.

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 will be provided to those employees after age 65 when they are automatically eligible for Medicare benefits to cover health costs.

In connection with the September 2003 acquisition of NCNG, we acquired certain pension and OPEB obligations of former employees of NCNG. The accrued pension benefits for this group were placed in a separate "frozen" plan at this date. The transferred active pension plan participants began accruing benefits under the Piedmont pension plan as of October 1, 2003. There were no assets attributable to the OPEB liability transferred from Progress. We merged the "frozen" qualified NCNG pension plan with the Piedmont pension plan as of December 31, 2006.

As a result of the Medicare Prescription Drug Improvement and Modernization Act of 2003, we amended our postretirement benefit plan in August 2005 to eliminate prescription drug coverage beginning January 1, 2006 for retirees who are Medicare eligible. This prescription drug benefit was replaced by a defined dollar benefit to pay the premiums for Medicare Part D.

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 also have a SERP covering all officers at the vice president level and above. It provides supplemental retirement income for officers whose benefits under the Company's qualified retirement plan are limited by tax code provisions. The level of insurance benefit and target retirement income benefits intended to be provided under the SERP depend upon the position of the officer. The SERP is funded by life insurance policies covering each officer, and the policy is owned exclusively by each officer. Premiums on these policies paid and expensed by us, as grossed up for taxes to the individual officer, for the years ended October 31, 2008, 2007 and 2006 are presented below.

	2008	2007	2006
	In thousands		
SERP premiums	$446	$455	$709

A reconciliation of changes in the plans' benefit obligations and fair value of assets for the years ended October 31, 2008 and 2007, and a statement of the funded status and the amounts reflected in the consolidated balance sheets for the years ended October 31, 2008 and 2007 are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2008	2007	2008	2007	2008	2007
			In thousands			
Accumulated benefit obligation at year end	$135,516	$169,367	$ 4,194	$ 4,845	N/A	N/A
Change in benefit obligation:						
Obligation at beginning of year	$188,698	$236,329	$ 4,845	$ 4,342	$ 33,612	$ 34,252
Adjustment to reflect prior obligation	—	—	—	857	—	—
Service cost	7,634	11,142	27	60	1,250	1,324
Interest cost	11,408	12,926	277	276	2,011	1,886
Plan amendments	(4,133)	(29,795)	127	—	—	—
Actuarial gain	(43,208)	(14,844)	(532)	(95)	(5,895)	(778)
Benefit payments	(16,939)	(27,060)	(550)	(595)	(2,866)	(3,072)
Obligation at end of year	$143,460	$188,698	$ 4,194	$ 4,845	$ 28,112	$ 33,612
Change in fair value of plan assets:						
Fair value at beginning of year	$224,954	$211,926	$ —	$ —	$ 20,435	$ 16,800
Actual return on plan assets	(68,351)	24,045	—	—	(5,671)	1,169
Employer contributions	11,000	16,500	550	595	3,624	5,538
Administrative expenses	(407)	(457)	—	—	—	—
Benefit payments	(16,939)	(27,060)	(550)	(595)	(2,866)	(3,072)
Fair value at end of year	$150,257	$224,954	$ —	$ —	$ 15,522	$ 20,435
Noncurrent assets	$ 6,797	$ 36,256	$ —	$ —	$ —	$ —
Current liabilities	—	—	(528)	(553)	—	—
Noncurrent liabilities	—	—	(3,666)	(4,292)	(12,591)	(13,177)
Net amount recognized	$ 6,797	$ 36,256	$(4,194)	$(4,845)	$(12,591)	$(13,177)
Amounts Not Yet Recognized as a Component of Cost and Recognized as Regulatory Asset or Liability(1):						
Unrecognized transition obligation	$ —	$ —	$ —	$ —	$ (3,335)	$ (4,002)
Unrecognized prior service (cost) credit	28,231	25,991	(127)	—	—	—
Unrecognized actuarial gain (loss)	(54,616)	(12,170)	498	(34)	989	2,227
Regulatory (asset) liability	(26,385)	13,821	371(3)	(34)(2)	(2,346)	(1,775)
Cumulative employer contribution in excess of cost	33,182	22,435	(4,565)	(4,811)	(10,245)	(11,402)
Net amount recognized	$ 6,797	$ 36,256	$(4,194)	$(4,845)	$(12,591)	$(13,177)

(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 $89 and a regulatory liability of $55.

(3) 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, 2008, 2007 and 2006 includes the following components.

	Qualified Pension			Nonqualified Pension			Other Benefits		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
	In thousands								
Service cost	$ 7,634	$ 11,142	$ 10,972	$ 27	$ 60	$ 66	$ 1,250	$ 1,324	$ 1,134
Interest cost	11,408	12,926	13,436	277	276	239	2,011	1,886	1,747
Expected return on plan assets	(16,895)	(17,013)	(17,112)	—	—	—	(1,461)	(1,273)	(1,151)
Amortization of transition obligation	—	—	—	—	—	—	667	667	667
Amortization of prior service cost	(1,893)	590	933	—	—	—	—	—	—
Amortization of actuarial loss (gain)	—	1,027	604	—	—	—	—	—	(218)
Net periodic benefit cost	254	8,672	8,833	304	336	305	2,467	2,604	2,179
Other changes in plan assets and benefit obligation recognized through regulatory asset or liability:									
Prior service cost (credit)	(4,133)	N/A	N/A	127	N/A	N/A	—	N/A	N/A
Net loss (gain)	42,446	N/A	N/A	(532)	N/A	N/A	1,237	N/A	N/A
Amounts recognized as a component of net periodic benefit cost:									
Transition obligation	—	N/A	N/A	—	N/A	N/A	(667)	N/A	N/A
Prior service credit	1,893	N/A	N/A	—	N/A	N/A	—	N/A	N/A
Total recognized in regulatory asset (liability)	40,206	—	—	(405)	—	—	570	—	—
Total recognized in net periodic benefit cost and regulatory asset (liability)	$ 40,460	$ 8,672	$ 8,833	$(101)	$ 336	$ 305	$ 3,037	$ 2,604	$ 2,179

The 2009 estimated amortization of the following items that are recorded in a regulatory asset or liability instead of accumulated OCI discussed above and expected refunds for our plans are as follows.

	Qualified Pension	Nonqualified Pension	Other Benefits
	In thousands		
Amortization of transition obligation	$ —	$ —	$667
Amortization of unrecognized prior service credit	(2,198)	20	—
Amortization of unrecognized actuarial loss	—	(20)	—
Refunds expected	(2,198)	—	667

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, 2008, the benchmark by plan was as follows.

Pension plan	8.15%
NCNG SERP	8.45%
Directors' SERP	8.56%
Piedmont SERP	8.23%
Tennessee SERP	8.07%
OPEB	8.50%

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, 2008 and 2007 are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2008	2007	2008	2007	2008	2007
Discount rate	8.15%	6.43%	8.46%	6.06%	8.50%	6.25%
Rate of compensation increase	3.97%	3.99%	N/A	N/A	N/A	N/A

The weighted average assumptions used to determine the net periodic benefit cost as of October 31, 2008, 2007 and 2006 are presented below.

	Qualified Pension			Nonqualified Pension		
	2008	2007	2006	2008	2007	2006
Discount rate	6.43%	5.78%	6.00%	6.06%	5.67%	5.75%
Expected long-term rate of return on plan assets	8.00%	8.50%	8.50%	N/A	N/A	N/A
Rate of compensation increase	3.99%	4.01%	4.05%	N/A	N/A	N/A

	Other Benefits		
	2008	2007	2006
Discount rate	6.25%	5.74%	5.89%
Expected long-term rate of return on plan assets	8.00%	8.50%	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, 2008, 2007 and 2006 are presented below.

	Pension Benefits			Other Benefits		
	2008	2007	Target	2008	2007	Target
Domestic equity securities	43%	48%	50%	35%	42%	50%
International equity securities	8%	10%	10%	23%	8%	10%
Fixed income securities	44%	41%	40%	37%	26%	40%
Cash	5%	1%	—%	5%	24%	—%
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. 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 2009.

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 2009.

	In thousands
Qualified pension plan	$11,000
Nonqualified pension plans	528
OPEB plan	3,400

Because 2008 is the first year of the MPP plan, we have made no contributions to the plan to date. We anticipate contributing $90,000 to the MPP plan in January 2009.

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 2008.

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

	Qualified Pension	Nonqualified Pension	Other Benefits
		In thousands	
2009	$11,689	$ 528	$ 2,884
2010	11,491	531	2,888
2011	10,839	517	2,855
2012	12,207	486	2,836
2013	12,063	480	2,877
2014-2018	66,110	2,063	16,342

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, 2008 and 2007 are presented below.

	2008	2007
Health care cost trend rate assumed for next year	8.25%	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	2017	2012

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.

	1% Increase	1% Decrease
	In thousands	
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost for the year ended October 31, 2008	$ 81	$ (88)
Effect on the health care cost component of the accumulated postretirement benefit obligation as of October 31, 2008	725	(709)

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. Full-time 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 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 are able to receive a company match of 100% up to the first 5% of eligible pay contributed. Employees are still able to 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 plan administrator. For employees who are automatically enrolled in the 401(k) plan, we will 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, 2008, 2007 and 2006, we made matching contributions to participant accounts as follows.

	2008	2007	2006
		In thousands	
401(k) matching contributions	$4,252	$3,191	$3,288

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.

8. Employee Share-Based Plans

Under the LTIP and Incentive Compensation Plan (ICP), approved by the Company's shareholders in March 2006, the Board of Directors has awarded units to eligible officers and other participants. Depending upon the level of performance achieved by Piedmont during multi-year performance periods, distribution of those awards may be made in the form of shares of common stock and cash withheld for payment of applicable taxes on the compensation. The LTIP and ICP require that a minimum threshold performance level be achieved in order for any award to be distributed. For the years ended October 31, 2008, 2007 and 2006, we recorded compensation expense, and as of October 31, 2008 and 2007, 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. Shares of common stock to be issued under the LTIP and ICP are contingently issuable shares and are included in our calculation of fully diluted earnings per share.

We have three awards under the LTIP and ICP with three-year performance periods ending October 31, 2008, October 31, 2009 and October 31, 2010. Fifty percent of the units awarded will be based on achievement of a target annual compounded increase in basic earnings per share (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 a target total annual shareholder return (increase in our common stock price plus dividends paid over the specified period of time) in comparison to a peer group consisting of the natural gas distribution companies formerly comprising the A. G. Edwards Large Natural Gas Distribution Index (peer group). The total shareholder return performance measure will be the registrant's 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 have 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 will occur over a three-year period. The second payout occurred in fiscal 2008.

Information for the LTIP and ICP for the years ended October 31, 2008, 2007 and 2006, and as of October 31, 2008 and 2007 is presented below.

	2008	2007	2006
		In thousands	
Compensation expense	$ 6,689	$1,666	$5,356
Tax benefit	1,723	654	2,111
Liability	10,749	6,200	

Based on current accrual assumptions, the expected payout for performance periods ending October 31, 2008, 2009 and 2010 will occur in the following fiscal years.

	2009	2010	2011
		In thousands	
Amount of payout	$5,329	$2,990	$1,941

Under our ICP, 65,000 restricted 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. The restricted shares shall vest and be payable on the following schedule only if he is an employee on the vesting date for each tranche:

	Projected Amount
	In thousands
20% on September 1, 2009	$374
30% on September 1, 2010	562
50% on September 1, 2011	936

During the vesting period, any dividends paid on these shares will be accrued and converted into additional shares at the closing price on the date of the dividend payment. The restricted shares and any additional shares accrued through dividends will vest according to the vesting schedule above. We are recording compensation under the ICP on the straight-line method.

Information for the restricted shares for the years ended October 31, 2008, 2007 and 2006 is presented below.

	October 31		
	2008	2007	2006
	In thousands, except shares		
Number of shares granted			65,000
Value at date of grant			$ 1,700
Compensation expense	$ 338	$336	$ 56
Tax (expense) benefit	(168)	132	22

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 4, we repurchase shares on the open market and such shares are then cancelled and become authorized but unissued shares available for issuance under our employee plans, including the ESPP, LTIP and ICP.

9. Income Taxes

The components of income tax expense for the years ended October 31, 2008, 2007 and 2006 are presented below.

	2008		2007		2006	
	Federal	State	Federal	State	Federal	State
			In thousands			
Charged to operating income:						
Current	$27,971	$ 6,679	$28,233	$ 4,987	$27,470	$ 4,977
Deferred	24,285	4,237	15,250	3,279	14,775	3,855
Amortization of investment tax credits	(358)	—	(434)	—	(534)	—
Total	51,898	10,916	43,049	8,266	41,711	8,832
Charged to other income (expense):						
Current	10,040	1,786	7,557	1,153	9,052	1,427
Deferred	(1,025)	(123)	4,644	957	1,107	301
Total	9,015	1,663	12,201	2,110	10,159	1,728
Total	$60,913	$12,579	$55,250	$10,376	$51,870	$10,560

A reconciliation of income tax expense at the federal statutory rate to recorded income tax expense for the years ended October 31, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Federal taxes at 35%	$64,225	$59,504	$55,867
State income taxes, net of federal benefit	8,176	6,745	6,864
Amortization of investment tax credits	(358)	(434)	(534)
Other, net	1,449	(189)	233
Total	$73,492	$65,626	$62,430

As of October 31, 2008 and 2007, deferred income taxes consisted of the following temporary differences.

	2008	2007
	In thousands	
Utility plant	$271,060	$239,448
Equity method investments	19,241	20,554
Revenues and cost of gas	17,370	23,741
Deferred cost	25,605	21,594
Other, net	(21,036)	(21,436)
Net deferred income tax liabilities	$312,240	$283,901

As of October 31, 2008 and 2007, total deferred income tax liabilities were $345 million and $321.3 million and total net deferred income tax assets were $32.8 million and $37.4 million, respectively. As of October 31, 2008 and 2007, these total net deferred income tax assets were net of a valuation allowance of $1.1 million and $.4 million, respectively, 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, 2008 and 2007, we had federal and state net operating

loss carryforwards of $6.6 million and $6.9 million, respectively, that expire from 2017 through 2025. We may use the loss carryforwards to offset taxable income, 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, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Balance at beginning of year	$ 394	$ 568	$583
Charged (credited) to income tax expense	720	(174)	(15)
Balance at end of year	$1,114	$ 394	$568

We adopted the provisions of FIN 48 on November 1, 2007. As a result of the implementation of FIN 48, 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 and October 31, 2008 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 year ended October 31, 2008 is presented below.

	In thousands
Balance, beginning of year (date of adoption)	$474
Increase from prior year's tax positions	72
Decrease from settlements with taxing authority	40
Balance, end of year	$506

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 $.1 million of interest related to unrecognized tax benefits during the year ended October 31, 2008.

For state tax purposes, we have unrecognized tax benefits related to the treatment of sales of certain assets that we anticipate will decrease by $.2 million due to a settlement with taxing authorities or the expiration of the statute of limitations within the next twelve months.

10. 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, 2008, 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.

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, 2008, 2007 and 2006, these transportation costs and the amounts we owed Cardinal as of October 31, 2008 and 2007 are as follows.

	2008	2007	2006
		In thousands	
Transportation costs	$4,116	$4,549	$4,684
Trade accounts payable	349	349	

Summarized financial information provided to us by Cardinal for 100% of Cardinal as of September 30, 2008 and 2007, and for the twelve months ended September 30, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Current assets	$10,010	$ 8,706	$
Non-current assets	80,851	83,388	
Current liabilities	5,229	3,814	
Non-current liabilities	31,439	33,637	
Revenues	13,670	15,369	15,524
Gross profit	13,670	15,369	15,524
Income before income taxes	7,050	8,371	8,785

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, 2008, 2007 and 2006, these gas storage costs and the amounts we owed Pine Needle as of October 31, 2008 and 2007 are as follows.

	2008	2007	2006
		In thousands	
Gas storage costs	$11,516	$11,727	$12,704
Trade accounts payable	1,019	932	

Summarized financial information provided to us by Pine Needle for 100% of Pine Needle as of September 30, 2008 and 2007, and for the twelve months ended September 30, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Current assets	$12,618	$11,178	$
Non-current assets	81,934	85,506	
Current liabilities	10,846	9,401	
Non-current liabilities	25,175	29,862	
Revenues	18,694	18,668	19,231
Gross profit	18,694	18,668	19,231
Income before income taxes	8,227	8,827	10,047

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, Georgia Natural Gas Company (GNGC), a subsidiary of AGL Resources, Inc., 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 includes a provision granting GNGC the option to purchase our ownership interest in SouthStar. By November 1, 2009, GNGC has the option to purchase our entire 30% interest effective on January 1, 2010. If GNGC exercises its option, the purchase price would be based on the market value of SouthStar as defined in the Restated Agreement.

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, 2008, 2007 and 2006, our operating revenues from these sales and the amounts SouthStar owed us as of October 31, 2008 and 2007 are as follows.

	2008	2007	2006
		In thousands	
Operating revenues	$14,624	$8,866	$21,598
Trade accounts receivable	1,202	1,650	

Summarized financial information provided to us by SouthStar for 100% of SouthStar as of September 30, 2008 and 2007, and for the twelve months ended September 30, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Current assets	$238,662	$204,598	$
Non-current assets	13,463	8,899	
Current liabilities	144,552	60,783	
Non-current liabilities	338	53	
Revenues	941,123	908,416	1,053,770
Gross profit	143,534	177,822	155,416
Income before income taxes	73,224	112,260	88,765

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. Phase one service to customers began April 1, 2007 when customers began injecting gas into storage for subsequent winter withdrawals, and Phase II service levels began on April 1, 2008. Hardy Storage is now in the final stages of phase III project construction. 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.

For 2008, we made equity contributions of $10.9 million to fund additional construction expenditures, with our total equity contributions for the project totaling $23.8 million at October 31, 2008. 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 May 2010. To the extent that more funding is needed, the members will evaluate funding options at that time.

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 interests in Hardy Storage.

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, 2008 and 2007 are as follows.

	2008	2007
	In thousands	
Guaranty liability	$ 1,234	$ 1,336
Amount outstanding under the construction financing	123,410	133,556

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

	2008	2007
	In thousands	
Gas storage costs	$9,219	$3,505
Trade accounts payable	774	791

Summarized financial information provided to us by Hardy Storage for 100% of Hardy Storage as of October 31, 2008 and 2007, and for the twelve months ended October 31, 2008, 2007 and 2006 is presented below.

	2008	2007	2006
		In thousands	
Current assets	$ 27,760	$ 19,972	$
Non-current assets	168,160	160,326	
Current liabilities	5,878	21,388	
Non-current liabilities	123,410	123,410	
Revenues	23,658	13,902	*
Gross profit	23,658	13,902	*
Income before income taxes	9,297	8,918	707

* Hardy Storage was not "in service" during the period presented. The income above is related to AFUDC associated with the financing and construction activities of the storage facilities, and is recorded in accordance with regulatory guidelines. 2006 includes interest expense from a construction loan and operating expenses in addition to AFUDC.

11. 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, 2008, 2007 and 2006, and as of October 31, 2008 and 2007 are presented below.

	Regulated Utility	Non-Utility Activities	Total
		In thousands	
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
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
Total assets	2,655,311	95,707	2,751,018
Equity method investments in non-utility activities	—	95,193	95,193
Construction expenditures	135,241	—	135,241
2006			
Revenues from external customers	$1,924,628	$ —	$1,924,628
Margin	523,479	—	523,479
Operations and maintenance expenses	219,353	503	219,856
Depreciation	89,696	4	89,700
Income from equity method investments	—	29,917	29,917
Interest expense	52,310	50	52,360
Operating income (loss) before income taxes	181,292	(623)	180,669
Income before income taxes	130,730	28,889	159,619
Construction expenditures	196,730	551	197,281

Reconciliations to the consolidated financial statements for the years ended October 31, 2008, 2007 and 2006, and as of October 31, 2008 and 2007 are as follows.

	2008	2007	2006
		In thousands	
Operating Income:			
Segment operating income before income taxes	$ 215,648	$ 188,144	$180,669
Utility income taxes	(62,814)	(51,315)	(50,543)
Non-utility activities before income taxes	277	518	623
Total	$ 153,111	$ 137,347	$130,749
Net Income:			
Income before income taxes for reportable segments	$ 183,499	$ 170,013	$159,619
Income taxes	(73,492)	(65,626)	(62,430)
Total	$ 110,007	$ 104,387	$ 97,189
Consolidated Assets:			
Total assets for reportable segments	$3,008,389	$2,751,018	
Eliminations/Adjustments	85,191	69,300	
Total	$3,093,580	$2,820,318	

12. Restructuring and Other Termination Benefits

In 2006, we restructured our management group and recognized a liability and expense of $7.9 million, which was included in the regulated utility segment in operations and maintenance expense for the cost of the restructuring program. This restructuring was the beginning of an ongoing, larger effort aimed at streamlining business processes, capturing operational and organizational efficiencies and improving customer service. This liability included early retirement for 22 employees of the management group and severance for 17 additional employees through further consolidation. Due to the short discount period, the liability for the program was recorded at its gross value. As of October 31, 2008 and 2007, there was no remaining liability for the management group restructuring program.

In 2007, we implemented additional 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 began initiating 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 have been consolidated in our central business office. These specific initiatives were largely completed as of October 31, 2008.

We have accrued costs in connection with these initiatives in the form of severance benefits to employees who will be either voluntarily or involuntarily severed. These benefits are under existing arrangements and are accounted for in accordance with SFAS No. 112, "Employers' Accounting for Postemployment Benefits." All costs are included in the regulated utility segment in "Operations and maintenance" expenses in the consolidated statements of income.

A reconciliation of activity to the liability as of October 31, 2008 and 2007 is as follows.

	2008	2007
	In thousands	
Beginning liability	$ 1,459	$ —
Costs incurred and expensed	—	3,648
Costs paid	(1,132)	(2,189)
Adjustment to accruals	(305)	—
Ending liability	$ 22	$ 1,459

13. Subsequent Events

On November 25, 2008, we filed an expedited petition with the PSCSC requesting approval to reduce the hedging horizon from 24 months to twelve months under the gas cost hedging plan, effective December 1, 2008. The PSCSC approved the request on December 10, 2008.

* * * * * *

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 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)
Fiscal Year 2007						
January 31	$677,241	$208,485	$81,697	$ 70,716	$ 0.95	$ 0.94
April 30	531,579	159,727	50,621	51,120	0.69	0.69
July 31	224,442	75,158	1,021	(9,140)	(0.12)	(0.12)
October 31	278,030	80,795	4,008	(8,309)	(0.11)	(0.11)

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. 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 in that they provide reasonable assurances 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 specified 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.

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 2008 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 29, 2008

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 Business Conduct and Ethics 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, 2008, 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, 2008.

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, 2008, 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, 2008, 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, 2008 of the Company and our report dated December 29, 2008 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 29, 2008

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 2009 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 2009 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 2009 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Business Conduct and Ethics that is applicable to all our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. The Code of Business Conduct and Ethics was filed as Exhibit 14.1 to our annual report on Form 10-K for the year ended October 31, 2003, and is available on our website at www.piedmontng.com. If we amend the Code of Business Conduct and Ethics or grant a waiver, including an implicit waiver, from the Code of Business Conduct and Ethics 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 2009 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 2009 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 2009 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 2009 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 B — Ratification of Deloitte & Touche LLP As Independent Registered Public Accounting Firm For Fiscal Year 2009" in our Proxy Statement for the 2009 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, 2008, are included in Item 8 of this report as follows:

Consolidated Balance Sheets — October 31, 2008 and 2007 37
Consolidated Statements of Income — Years Ended October 31, 2008, 2007 and 2006 38
Consolidated Statements of Cash Flows — Years Ended October 31, 2008, 2007 and 2006 39
Consolidated Statements of Stockholders' Equity — Years Ended October 31, 2008, 2007 and 2006 40
Notes to Consolidated Financial Statements 41

(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 10.21 are management contracts or compensatory plans or arrangements.

3.1 Articles of Incorporation of the Company as of March 3, 2006, filed in the Department of State of the State of North Carolina (Exhibit 4.1, Form S-8 Registration Statement No. 333-132738).

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 Rights Agreement, dated as of February 27, 1998, between Piedmont and Wachovia Bank, N.A., as Rights Agent, including the Rights Certificate (Exhibit 10.1, Form 8-K dated February 27, 1998).

4.11 Agreement of Substitution and Amendment of Common Shares Rights Agreement, dated as of December 18, 2003, between Piedmont and American Stock Transfer and Trust Company, Inc. (Exhibit 4.10, Form S-3 Registration Statement No. 333-111806).

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

4.13 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).

4.14 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).

4.15 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).

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

4.17 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).

4.18 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).

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

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

4.21 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).

4.22 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).

4.23 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 Form of Award Agreement under Executive Long-Term Incentive Plan (Exhibit 10.5, Form 10-K for the fiscal year ended October 31, 2006).

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

10.5 Employment Agreement with Thomas E. Skains, dated December 1, 1999 (Exhibit 10.40, Form 10-K for the fiscal year ended October 31, 1999).

10.6 Employment Agreement with Franklin H. Yoho, dated March 18, 2002 (Exhibit 10.23, Form 10-K for the fiscal year ended October 31, 2002).

10.7 Employment Agreement with Michael H. Yount, dated May 1, 2006 (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2006).

10.8 Employment Agreement with Kevin M. O'Hara, dated May 1, 2006 (Exhibit 10.2, Form 10-Q for the quarter ended April 30, 2006).

10.9 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).

10.10 Schedule of Severance Agreements with Executives (Exhibit 10.2a, Form 10-Q for the quarter ended July 31, 2007).

10.11 Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (Exhibit 10.1, Form 8-K dated December 10, 2004).

10.12 Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (with supplemental retirement benefit) (Exhibit 10.14, Form 10-K for the fiscal year ended October 31, 2004).

10.13 Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (without supplemental retirement benefit) (Exhibit 10.15, Form 10-K for the fiscal year ended October 31, 2004).

10.14 Piedmont Natural Gas Company, Inc. Incentive Compensation Plan (Exhibit 10.1, Form 8-K dated March 3, 2006).

10.15 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).

10.16 Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Short-Term Incentive Plan (STIP) (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2007).

10.17 Form of Performance Unit Award Agreement (Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2007).

10.18 Amendment No. 1 to the Piedmont Natural Gas Company Executive Long-Term Incentive Plan, dated September 7, 2007 (Exhibit 10.22, Form 10-K for the fiscal year ended October 31, 2007).

10.19 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).

10.20 Incentive Compensation Plan Interpretive Guidelines as of September 7, 2007 (Exhibit 10.24, Form 10-K for the fiscal year ended October 31, 2007).

10.21 Executive Long-Term Incentive Plan, dated February 27, 2004 (Corrected) (Exhibit 10.1, Form 10-Q for quarter ended April 30, 2008).

Other Contracts:

10.22 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).

10.23 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).

10.24 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).

10.25 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).

10.26 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).

10.27 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).

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

10.29 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).

10.30 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).

10.31 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).

10.32 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Bank of America, N.A., dated October 27, 2008.

10.33 Revolving Credit Facility between Piedmont Natural Gas Company, Inc. and Branch Banking and Trust Company, dated October 29, 2008.

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 29, 2008

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 Thomas E. Skains	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: December 29, 2008	
/s/ David J. Dzuricky David J. Dzuricky	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: December 29, 2008	
/s/ Jose M. Simon Jose M. Simon	Vice President and Controller (Principal Accounting Officer)
Date: December 29, 2008	

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



END



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