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

FORM 10-K

(Mark One)

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

For the fiscal year ended October 31, 2015

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

State the aggregate market value of the voting common equity held by non-affiliates of the registrant as of April 30, 2015.

Common Stock, no par value - $2,923,039,979

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

Class	Outstanding at December 11, 2015
Common Stock, no par value	80,985,282

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the 2016 Proxy Statement for the Annual Meeting of Shareholders are incorporated by reference into Part III.

Piedmont Natural Gas Company, Inc.

2015 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. Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Piedmont" means consolidated Piedmont Natural Gas Company, Inc. and its subsidiaries.

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 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, regulated interstate natural gas transportation and storage and regulated intrastate natural gas transportation businesses.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We provide service from resource centers in Anderson, 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 natural gas service to Greenville, 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 three reportable business segments, regulated utility, regulated non-utility activities and unregulated non-utility activities, with the regulated utility segment being the largest. Factors critical to the success of the regulated utility include operating a safe and reliable natural gas distribution system and the ability to recover the costs and expenses of the business in the rates charged to customers. The regulated non-utility activities segment consists of our equity method investments in regulated energy-related joint ventures that are held by our wholly-owned subsidiaries. The unregulated non-utility activities segment consists primarily of our equity method investment in an unregulated energy-related joint venture that is held by a wholly-owned subsidiary. The percentages of assets as of October 31, 2015 and earnings before taxes by segment for the year ended October 31, 2015 are presented below.

	Assets	Earnings Before Taxes
Regulated Utility	**96%**	**85%**
Non-utility Activities:		
Regulated non-utility activities	**3%**	**7%**
Unregulated non-utility activities	**1%**	**8%**
Total non-utility activities	**4%**	**15%**

Operations of our segments are conducted within the United States of America. For further information on equity method investments and business segments, see Note 13 and Note 15, respectively, to the consolidated financial statements in this Form 10-K.

Operating revenues shown in the Consolidated Statements of Comprehensive Income represent revenues from the regulated utility segment. The cost of purchased gas is a component of operating revenues. Increases or decreases in prudently incurred purchased gas costs from suppliers are passed through to customers through purchased gas adjustment (PGA) procedures. Therefore, our operating revenues are impacted by changes in gas costs as well as by changes in volumes of gas sold and transported. Secondary market transactions consist of off-system sales and capacity release arrangements and asset management arrangements and are part of our regulatory gas supply management program with regulator-approved sharing mechanisms between our utility customers and our shareholders. Earnings or losses from equity method investments of the regulated and unregulated non-utility activities segments are included in "Income from equity method investments" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. All other revenues and expenses of the regulated and unregulated non-utility activities segments are included in "Non-operating income" in "Other Income

(Expense)" in the Consolidated Statements of Comprehensive Income.

Operating revenues by major customer class for the years ended October 31, 2015 and 2014 are presented below.

	2015	2014
Residential customers	**48%**	46%
Commercial customers	**27%**	27%
Large volume customers, including industrial, power generation and resale customers	**15%**	14%
Secondary market activities	**10%**	12%
Other sources	**—%**	1%
Total	**100%**	100%

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. The NCUC also regulates us as to the issuance of long-term debt and equity securities.

We are also subject to various federal regulations that affect our utility and non-utility operations. 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 certification and siting of new interstate natural gas pipeline projects, the purchase and sale of, the prices paid for, and the terms and conditions of service for the interstate transportation and storage of natural gas, regulations of the U.S. Department of Transportation (DOT) that affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency (EPA) relating to the environment, including proposed air emissions regulations that would expand to include emissions of methane. In addition, we are subject to numerous other regulations, such as those relating to employment and benefit practices that are generally applicable to companies doing business in the United States of America.

We hold non-exclusive franchises for natural gas service in many of the communities we serve, with expiration dates from November 2015 to 2058. The franchises are adequate for the operation of our gas distribution business and do not contain materially burdensome restrictions or conditions. From time to time, some of our franchise agreements expire; however, we continue to operate in those areas pursuant to the provisions of the expired franchises with no significant impact on our business. Depending on the jurisdiction, we believe that these franchises will be renewed or that service will be continued in the ordinary course of business while we negotiate renewals or continue to operate under our state-granted franchise rights without a specific franchise agreement with each city or municipality. The likelihood of cessation of service under an expired franchise is remote, and we do not believe there will be a material adverse impact on us.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to recover the cost of natural gas we purchased for our customers and our operating expenses and to earn a fair rate of return on invested capital for our shareholders. The traditional utility rate design provides for the collection of margin revenue largely based on volumetric throughput which can be affected by customer consumption patterns, weather, conservation, price levels for natural gas or general economic conditions. By continually assessing alternative rate structures and cost recovery mechanisms that are more appropriate to the changing energy economy and through requests filed with our regulatory commissions, we have secured alternative rate structures and cost recovery mechanisms designed to allow us to recover certain costs through tracking mechanisms or riders without the need to file general rate cases. Our ability to earn our authorized rates of return is based in part on our ability to reduce or eliminate regulatory lag through rate stabilization adjustment (RSA) filings, integrity management riders (IMRs) or similar mechanisms and also by improved rate designs that decouple the recovery of our approved margins from customer usage patterns impacted by seasonal weather patterns and customer conservation. This allows a better alignment of the interests of our shareholders and customers.

In North Carolina, we have a margin decoupling mechanism that provides for the recovery of our approved margin from residential and commercial customers on an annual basis independent of consumption patterns. The margin decoupling mechanism provides for semi-annual rate adjustments to refund any over-collection of margin or to recover any under-collection of margin. In South Carolina, we operate under a RSA mechanism that achieves the objective of margin decoupling for residential and commercial customers with a one year lag. Under the RSA mechanism, we reset our rates based on updated costs and revenues on an annual basis. We also have a weather normalization adjustment (WNA) mechanism for residential and commercial customers in South Carolina for bills rendered during the months of November through March and in Tennessee for bills rendered during the months of October through April that partially offsets the impact of colder- or warmer-than-normal winter weather on our margin collections. Our WNA formulas calculate the actual weather variance from normal, using 30 years of history, and increase margin revenues when weather is warmer than normal and decrease margin revenues when weather is colder than normal. The WNA formulas do not ensure full recovery of approved margin during periods when customer consumption patterns vary from those used to establish the WNA factors and when weather is significantly warmer or colder than normal. Weather in 2015, on average over our three-state market area, was 6% colder than normal and 3% warmer than 2014. For the year ended October 31, 2015, the margin decoupling mechanism in North Carolina decreased margin by $27 million, and the WNA mechanisms in South Carolina and Tennessee together decreased margin by $6.8 million.

With approval in North Carolina and Tennessee in December 2013, we have IMRs that separately track and recover, outside of general rate cases, certain costs associated with capital expenditures to comply with pipeline safety and integrity requirements. The first Tennessee IMR rate adjustment was recognized in earnings through customer billings beginning in January 2014, and the first North Carolina IMR rate adjustment was recognized in earnings through customer billings beginning in February 2014.

In all three states, the gas cost portion of our costs is recoverable through PGA procedures and is not affected by the margin decoupling mechanism or the WNA mechanism. Through the use of various tariff mechanisms and fixed-rate contracts, we are able to achieve a higher degree of margin stabilization. For further information on state commission regulation, see Note 3 to the consolidated financial statements in this Form 10-K. The following table presents the breakdown of our gas utility margin for the years ended October 31, 2015, 2014 and 2013.

	2015	2014	2013
Fixed margin (from margin decoupling in North Carolina, facilities charges to our customers, Tennessee and North Carolina IMRs in 2015 and 2014 only and fixed-rate contracts)	**75%**	72%	73%
Semi-fixed margin (RSA in South Carolina and WNA in South Carolina and Tennessee)	**14%**	16%	16%
Volumetric or periodic renegotiation (including secondary marketing activity)	**11%**	12%	11%
Total	**100%**	100%	100%

The natural gas distribution business is seasonal in nature as variations in weather conditions and our regulated utility rate designs 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 in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our Strategies

We monitor our progress and measure our performance related to our strategic directives and business objectives over the course of each fiscal year. The metrics we use to measure our performance include, but are not limited to, earnings per share (EPS) and EPS growth, total shareholder return compared to our industry peer group, return on invested capital, return on equity, utility margin, investment grade credit ratings, customer growth, utility customer satisfaction and loyalty, operations and maintenance (O&M) expense discipline, employee health and safety, pipeline safety and sustainable business practices.

Safety is a critical component to our ongoing success as a company, and we have always placed the highest priority on the safety of our system, public safety and employee safety. We must comply with laws that regulate system integrity as well as new rulemaking proceedings under the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. We are subject to DOT and state regulation of our pipeline and related facilities and have ongoing transmission and distribution pipeline integrity programs to inspect our system for anomalies, corrosion and leaks as well as monitoring key metrics of our system for its safe operation. We anticipate federal legislative and regulatory enactments will increase in scope and add further requirements and costs to our pipeline safety and integrity programs and our capital and O&M expenditure programs. Items that federal regulators continue to discuss include possible mandates addressing the integrity verification process of maximum allowable operating pressure of transmission pipelines. We will continue our efforts to educate the public about our pipeline system in an effort to decrease third-party excavation damage, which is the greatest cause of damage on our system. We encourage focused efforts to improve the safety of our industry as a whole.

We believe natural gas is a safe and reliable energy source that is clean, affordable, reliable and environmentally responsible, as well as being domestically abundant. We incorporate this message into our pursuit of growth in our core residential, commercial, industrial and power generation markets as well as complementary energy-related investments. We promote the increased awareness and use of natural gas and want our customers to choose us because of the value of natural gas and the quality of our service to them.

Our business model supports new clean energy technologies and energy efficiencies in the end use of natural gas. We seek opportunities for regulatory innovation and strategic alliances to advance our customers' interests in energy conservation, efficiency and environmental stewardship. We are promoting the direct use of natural gas in more homes, businesses, industries and vehicles as we strongly believe that the expanded use of clean, efficient, abundant and domestic natural gas with its relatively low emissions can help revitalize our economy, reduce both overall energy consumption and greenhouse gas emissions and enhance our national energy security.

We see an opportunity in the clean energy technology of compressed natural gas (CNG) vehicles. We have converted 31% of our 1,100 vehicle fleet to CNG. As of October 31, 2015, we have approximately $19.4 million of utility plant in our three-state territory related to our CNG fueling stations that is included in the Consolidated Balance Sheets in "Utility plant in service." We have been allowed by the NCUC, PSCSC and TRA to include this utility plant in service in our utility rate base and have the opportunity to earn an allowed rate of return in the jurisdictions. In an order issued in October 2015, the TRA stated that we may seek recovery of our recent investments in CNG equipment in that state in utility rate base in our next general rate proceeding.

We continued to execute our plan to build CNG fueling stations in our service area for use by our own vehicle fleet as well as by third-party fleets and other customers when there is sufficient demand to allow us to earn an adequate rate of return. We currently operate ten CNG fueling stations in our three-state service territory. We are also actively pursuing building customer-owned CNG fueling stations at commercial customers' sites for use by their commercial fleets. There are currently fifteen customer-owned stations in our service territory.

Natural gas power plants continue to be a popular alternative to coal-fired electric generation plants because they emit significantly less carbon emissions than the coal power plants they replace and can cost less to operate. In recent years, we have completed pipeline expansion projects to provide long-term natural gas delivery service to new natural gas-fired power generation facilities in our market area. We currently provide service to 25 power generation customer accounts. In addition to delivering the natural gas supply to the new natural gas-fired power plants, the construction of natural gas pipelines for two of these projects increased our natural gas infrastructure in the eastern part of North Carolina with enhancement of future opportunities for economic growth and development.

Our capital program primarily supports our system infrastructure and the growth in our customer base. We are investing in our pipeline integrity, safety and compliance programs, and systems and technology infrastructure to enhance our pipeline system and integrity. For further information on our forecasted capital investments for fiscal 2016 – 2018, see "Cash Flows from Investing Activities" in Item 7 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations.

We strive to achieve excellence in service to our customers and in our business operations with every customer contact we make. In our business practices, we promote a sustainable enterprise by reducing our impact on the environment, developing strong communities in which we operate and enhancing long-term shareholder value. We support our employees with improved processes and technology to better serve our customers while continuing to build a healthy, high performance culture in order to recruit, retain and motivate our workforce.

Our financial strength and flexibility is critical to our success as a company. We will continue our efforts to maintain our financial strength, including a strong balance sheet, investment-grade credit ratings and continued access to capital markets. We evaluate the strength of financial institutions with which we have working relationships to ensure access to funds for operations and capital investments. Our capital plan includes maintaining a capitalization ratio of 50 – 60% in total debt and 40 – 50% in common equity. We will continue our efforts to control our operating costs, implement new technologies and work with our state regulators to maintain fair rates of return and innovative rate designs for the benefit of our customers and shareholders.

We continue to pursue strategic opportunities aligned with our core natural gas or complementary energy related businesses. It is our long-term strategic intent for our joint venture portfolio to be primarily weighted towards regulated and asset-based investments in natural gas infrastructure. We analyze and evaluate potential projects based on projected rates of return commensurate with the 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, specifically annual approved budgets, 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.

Regarding our complementary energy-related businesses, we are a 24% equity member of Constitution Pipeline Company, LLC, whose purpose is to construct and operate 124 miles of interstate natural gas pipeline and related facilities connecting shale natural gas supplies and gathering systems in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York. We have committed to fund an amount in proportion to our ownership interest for the development and construction of the new pipeline, which is expected to cost approximately $834 million. For further information on this equity method investment, see Note 13 to the consolidated financial statements in this Form 10-K.

Also, we are a 10% equity member of Atlantic Coast Pipeline, LLC (ACP), a Delaware limited liability company. ACP intends to construct, operate and maintain 564 miles of natural gas pipeline with associated compression from West Virginia through Virginia into eastern North Carolina. The pipeline will provide wholesale natural gas transportation services for Marcellus and Utica gas supplies into southeastern markets. We have committed to fund an amount in proportion to our ownership interest of 10% for the development and construction of the new pipeline, which is expected to cost between $4.5 billion to $5 billion. For further information on this equity method investment, see Note 13 to the consolidated financial statements in this Form 10-K.

On October 24, 2015, we entered into an Agreement and Plan of Merger (Merger Agreement) with Duke Energy Corporation (Duke Energy) and Forest Subsidiary, Inc. (Merger Sub), a new wholly owned subsidiary of Duke Energy. The Merger Agreement provides for the merger of the Merger Sub with and into Piedmont, with Piedmont surviving as a wholly owned subsidiary of Duke Energy (the Acquisition). At the effective time of the Acquisition, subject to receipt of required shareholder and regulatory approvals and meeting specified customary closing conditions, each share of Piedmont common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $60 in cash per share, without interest, less any applicable withholding taxes. Upon consummation of the Acquisition, Piedmont common stock will be delisted from the New York Stock Exchange. For further information on the Acquisition, see Item 1A. Risk Factors, "Forward Looking Statements" in Item 7, and Note 2 and Note 16 to the consolidated financial statements in this Form 10-K.

Operating Statistics

The following is a five-year comparison of operating statistics for the years ended October 31, 2011 through 2015.

	2015	2014	2013	2012	2011
Operating Revenues (in thousands):					
Sales and Transportation:					
Residential	**$ 656,182**	$ 683,848	$ 588,546	$ 534,321	$ 658,892
Commercial	**370,339**	397,004	331,831	301,013	379,846
Industrial	**106,986**	115,515	113,182	95,177	104,774
Power Generation	**85,650**	85,902	64,109	36,027	28,969
For Resale	**10,208**	9,587	9,549	9,512	9,692
Total	**1,229,365**	1,291,856	1,107,217	976,050	1,182,173
Secondary Market Sales	**134,322**	169,543	164,130	140,380	244,824
Miscellaneous	**8,031**	8,589	6,882	6,350	6,908
Total	**$ 1,371,718**	$ 1,469,988	$ 1,278,229	$ 1,122,780	$ 1,433,905
Gas Volumes - Dekatherms (in thousands)					
System Throughput:					
Residential	**61,004**	61,782	55,283	43,788	57,778
Commercial	**44,616**	44,259	39,602	33,774	40,749
Industrial	**96,380**	95,780	95,019	89,234	90,842
Power Generation	**262,161**	201,707	190,862	151,675	83,522
For Resale	**7,362**	7,174	6,834	5,829	6,870
Total	**471,523**	410,702	387,600	324,300	279,761
Secondary Market Sales	**30,759**	20,516	41,605	48,373	48,835
Number of Customers Billed (12-month average):					
Residential	**916,719**	903,067	890,887	878,851	871,401
Commercial	**98,544**	97,288	96,009	95,100	94,485
Industrial	**2,283**	2,279	2,271	2,265	2,265
Power Generation	**25**	25	24	22	22
For Resale	**15**	16	15	15	15
Total	**1,017,586**	1,002,675	989,206	976,253	968,188
Cost of Gas (in thousands):					
Natural Gas Commodity Costs	**$ 450,100**	$ 621,604	$ 526,703	$ 379,145	$ 666,930
Capacity Demand Charges	**131,196**	144,313	151,369	129,090	136,139
Natural Gas Withdrawn From (Injected Into) Storage, net	**25,715**	(13,578)	(5,867)	27,580	11,362
Regulatory Charges (Credits), net	**37,413**	27,441	(15,466)	11,519	45,835
Total	**$ 644,424**	$ 779,780	$ 656,739	$ 547,334	$ 860,266

Supply Available for Distribution (dekatherms in thousands):

Natural Gas Purchased	**144,862**	134,986	142,884	132,426	155,550
Transportation Gas	**359,986**	299,166	287,980	235,474	175,005
Natural Gas Withdrawn From (Injected Into) Storage, net	**(573)**	(1,232)	(509)	(378)	196
Company Use	**(700)**	(731)	(369)	(296)	(309)
Total	**503,575**	432,189	429,986	367,226	330,442

During the year ended October 31, 2015, we delivered 471.5 million dekatherms (one dekatherm equals 1,000,000 BTUs) to our utility retail customers compared to 410.7 million dekatherms the year before. Of this amount, 365.9 million dekatherms of gas were sold to or transported for large volume customers compared with 304.7 million dekatherms in 2014. Of these volumes sold to or transported for large volume customers, we transported 262.2 million dekatherms in 2015 to power generation facilities compared with 201.7 million dekatherms in the prior year. The margin earned from power generation customers is largely based on fixed monthly demand charge contracts and does not vary significantly based on the volumes transported. Deliveries to temperature-sensitive residential and commercial customers, whose consumption varies with the weather, totaled 105.6 million dekatherms in 2015, compared with 106 million dekatherms in 2014. Weather, as measured by degree days, was 6% colder than normal in 2015 and 9% colder than normal in 2014.

We have added increasing numbers of customers in our service areas each year over our last four fiscal years. Affordable and stable wholesale natural gas costs continued to favorably position natural gas relative to other energy sources. Continued improvement in economic conditions and targeted marketing programs on the benefits of natural gas resulted in growth in both the residential new construction and commercial markets. Growth in residential conversion and industrial markets decreased slightly in fiscal 2015, reflecting a longer sales cycle for conversions and a decline in readily available opportunities for industrial conversions.

We forecast continuing gross customer growth in fiscal 2016 of approximately 1.6 – 2% on our base of approximately one million utility retail customers. Total net customers billed increased 2% in fiscal year 2015 compared to 2014.

Natural Gas Utility Operations

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 design 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 monthly 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, 2015, we had contracts for the following pipeline firm transportation in dekatherms per day.

Williams – Transco	**632,100**
Kinder Morgan – Tennessee Pipeline	**37,000**
Spectra – Texas Eastern (partially through East Tennessee and Transco)	**11,700**
Spectra – East Tennessee (through Transco)	**44,800**
Oneok – Midwestern (through East Tennessee)	**25,000**
Columbia Pipeline Group – Columbia Gas (through Transco and Columbia Gulf)	**42,800**
Columbia Pipeline Group – Columbia Gulf	**41,000**
Total	**834,400**

As of October 31, 2015, we had the following assets or contracts for local peaking facilities and storage for seasonal or peaking capacity in dekatherms of daily deliverability to meet the firm demands of our markets with deliverability from 5 days to one year.

Piedmont Liquefied Natural Gas (LNG)	**270,000**
Pine Needle LNG (through Transco)	**263,400**
Williams – Transco Storage	**86,100**
Columbia Pipeline Group – Columbia Gas Storage	**96,400**
Hardy Storage (through Columbia Gas and Transco)	**68,800**
Kinder Morgan – Tennessee Pipeline Storage	**55,900**
Total	**840,600**

As of October 31, 2015, we own or have under contract 35.7 million dekatherms of storage capacity, either in the form of underground storage or LNG. This capacity is used to supplement or replace regular pipeline supplies.

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 heating season (principally November through March) when customer demand is higher. During the year ended October 31, 2015, the amount of natural gas in storage varied from 13.3 million dekatherms to 25.8 million dekatherms, and the commodity cost of this gas in storage varied from $54.4 million to $114.5 million.

Natural gas development and production in North America continues to provide abundant supply and price stability and moderation for natural gas as an energy commodity. With lower gas prices over the past eight years, we have been able to significantly lower the cost of gas to our customers with multiple filings for reductions in the wholesale natural gas component of customer rates in the three jurisdictions that we serve. Currently, natural gas has a price advantage over other fuels, and it is anticipated that the cost of natural gas will remain competitive due to abundant sources of shale gas reserves.

We purchase our natural gas supplies by contracting primarily with major and independent producers and marketers. We also purchase a diverse portfolio of transportation and storage services from interstate pipelines that are regulated by the FERC. Peak-use requirements are met through the use of company owned storage facilities, pipeline transportation capacity, purchased storage services and other supply sources. We have been able to obtain sufficient supplies of natural gas to meet customer requirements, and with the prospect of abundant domestic shale natural gas supplies and our contracted pipeline capacity, we believe that we will be able to meet our market demands in the future.

When firm pipeline services or contracted gas supplies are temporarily not needed due to market demand fluctuations, we may release these services and supplies in the secondary market under FERC-approved capacity release provisions or make wholesale secondary market sales. The proceeds from those transactions are used to reduce the cost of natural gas we charge to customers through sharing mechanisms that are in place in all three jurisdictions whereby customers are allocated 75% of the savings through the incentive plans. For further information on these regulatory sharing mechanisms, see Note 3 to the consolidated financial statements in this Form 10-K.

We continue to diversify our supply portfolio by contracting to bring abundant and low cost natural gas supplies from the Marcellus supply basin to our natural gas markets in the Carolinas. In November 2012, we signed a long-term contract with Cabot Oil & Gas (Cabot) to purchase firm, price-competitive Marcellus gas supplies. We also signed a long-term firm capacity contract with Williams – Transco under its Leidy Southeast expansion project to transport the Marcellus based Cabot gas supplies to our markets. Partial service under these contracts began in December 2015. In December 2012, we also signed a long-term firm capacity contract with Williams – Transco under its Virginia Southside expansion project that began service in September 2015. We believe these new supply and capacity arrangements provide diversification, reliability and gas cost benefits to Piedmont's customers across the Carolinas. Also, with the new ACP project that is targeted to be in service in late 2018, we will have additional pipeline capacity from diversified gas supply basins under a long-term firm service agreement that we executed with ACP, subject to FERC approval of the project.

Competition

Our 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, comfort, convenience, 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 lead to slower customer growth or customer conservation, or both, resulting in reduced gas purchases and customer billings. In turn, this can impact our capital expenditures and overall cash needs, including working capital needs. The direct use of natural gas in homes and businesses is the most efficient and cost effective use of natural gas and results in overall lower carbon emissions. However, the use of natural gas for power generation also adds significant value as a result of natural gas' environmental attributes, competitive cost advantage and efficiency of delivery.

During the year ended October 31, 2015, approximately 3% 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, with fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on relative prices of energy. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the U.S. dollar versus other currencies. Our liquidity could be impacted, either positively or negatively, as a result of changes in oil and natural gas prices and the alternate fuel decisions made by industrial customers.

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, 2015, no bypass occurred. The future level of bypass activity cannot be predicted.

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Natural gas for power generation competes with other fuel sources for the generation of electricity, including coal, nuclear and renewable resources. Additionally, as with industrial customers, we compete with other pipeline providers to serve the power generation plants.

Other

During the year ended October 31, 2015, our largest revenue generating customer contributed $86.3 million, or 6%, of total operating revenues. Our largest margin generating customer contributed $73.2 million, or 10% of total margin. Our largest revenue and margin generating customer is the same customer.

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

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

Costs incurred for natural gas, labor, employee benefits, consulting and construction are the business charges that we incur that are most significantly impacted by inflation. Changes to the cost of gas are generally recovered through regulatory mechanisms and do not significantly impact net income. Labor and employee benefits are components of the cost of service, and construction costs less utility deferred income taxes are the primary components of rate base. In order to recover increased costs and earn a fair return on rate base, we file general rate cases for review and approval by regulatory authorities when necessary. The ratemaking process has a natural time lag between incurrence of additional costs and the setting of new rates. See the discussion above for information on IMRs to track and recover certain capital costs in North Carolina and Tennessee outside of a general rate case. In South Carolina, we operate under a RSA mechanism that reduces regulatory lag to one year, but we reserve the right to file general rate cases when necessary. Regulatory lag can impact earnings.

As of October 31, 2015, our fiscal year end, we had 1,943 employees compared with 1,879 as of October 31, 2014.

Our reports on Form 10-K, Form 10-Q and Form 8-K, and any 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

Market Risks

An overall economic downturn could negatively impact our earnings.

Any weakening of economic activity in our markets could result in a loss of customers, a decline in customer additions, especially in the new home construction market, or a decline in 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. Deteriorating economic conditions could also affect pension costs by reducing the value of the investments that fund our pension plan and negatively affect actuarial assumptions, resulting in increased pension costs. The foregoing could negatively affect earnings and liquidity, reducing our ability to grow the business.

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

A supply and demand imbalance in natural gas markets could cause an increase in the price of natural gas. Recently, the increased production of U.S. shale natural gas has put downward pressure on the wholesale cost of natural gas; accordingly, restrictions or regulations on shale gas production could cause natural gas prices to increase. Additionally, the

Commodity Futures Trading Commission (CFTC) under the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act has regulatory authority of the over-the-counter derivatives markets. Regulations affecting derivatives could increase the price of our gas supply. The prudently incurred cost we pay for natural gas is passed directly through to our customers. Therefore, significant increases in the price of natural gas may cause our existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders and new customers to select alternative sources of

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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 high, our working capital costs could increase due to higher carrying costs of gas storage inventories, adding further upward pressure on customer bills. Customers may have trouble paying those higher bills which may lead to bad debt expenses, ultimately reducing our earnings.

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

The natural gas business is competitive, and we face competition from other companies that supply energy, including electric companies, oil and propane dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. A significant competitive factor is price.

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

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

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. Warmer-than-normal weather can reduce our utility margins as customer consumption declines. We have in place regulatory mechanisms and rate design that normalize the margin we collect from certain customer classes during the winter, providing for an adjustment up or down, to take into account warmer-than-normal or colder-than-normal weather. If our rates and tariffs are modified to eliminate weather protection provisions, such as weather normalization and rate decoupling tariffs, then we would be exposed to significant risk associated with weather. Additionally, our weather normalization mechanisms do not ensure full protection, especially for significantly warmer-than-normal winter weather. As a result of these events, our results of operations and earnings could vary and be negatively impacted.

Commercial Risks

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

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

The availability of adequate interstate pipeline transportation capacity and natural gas supply may decrease.

We purchase almost 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 or reduction in that supply or interstate pipeline capacity due to events including but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyber-attacks or other acts of war, or legislative or regulatory actions or requirements, including remediation

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related to integrity inspections, could reduce our normal interstate supply of gas and thereby reduce our earnings. Moreover, if additional natural gas infrastructure, including but not limited to exploration and drilling rigs and platforms, processing and gathering systems, off-shore pipelines, interstate pipelines and storage, cannot be built at a pace that meets demand, then our growth opportunities would be limited and our earnings negatively impacted.

Our business activities are concentrated in three states.

Approximately 96% of our assets and 85% of our earnings before taxes come from our regulated utility business. Further, approximately 70% of our natural gas utility customers, including customers served by three North Carolina municipalities who are our wholesale customers, and most of our utility transmission and distribution pipelines are located in North Carolina, with the remainder located in South Carolina and Tennessee. Changes in the regional economies, politics, regulations and weather patterns of North Carolina, South Carolina and Tennessee could negatively impact the growth opportunities available to us and the usage patterns and financial condition of customers and could adversely affect our earnings.

We may not be able to complete necessary or desirable pipeline expansion or infrastructure development or maintenance projects, which may delay or prevent us from serving our customers or expanding our business.

In order to serve current or new customers or expand our service to existing customers, we need to maintain, expand or upgrade our distribution, transmission and/or storage infrastructure, including laying new pipeline and building compressor stations. Various factors may prevent or delay us from completing such projects or make completion more costly, such as the inability to obtain required approval from local, state and/or federal regulatory and governmental bodies, public opposition to the project, inability to obtain adequate financing, competition for labor and materials, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to rights-of-way, construction or other material development components. As a result, we may not be able to adequately serve existing customers or support customer growth, or could result in higher than anticipated cost, both of which would negatively impact our earnings.

Financial Risks

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

Our ability to obtain adequate and cost effective financing depends in part on our credit ratings. A negative change in our ratings outlook or any downgrade in our current investment-grade credit ratings by our rating agencies, particularly below investment grade, could adversely affect our costs of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit our access to private credit markets and increase the costs of borrowing under available credit lines. Should our credit ratings be downgraded, the interest rate on our borrowings under our revolving credit agreement and unsecured commercial paper (CP) program, as well as on any future public or private debt issuances, would increase. An increase in borrowing costs without the ability to recover 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.

We may be unable to access capital or the cost of capital may significantly increase.

Our ability to obtain adequate and cost effective financing is dependent upon the liquidity of the financial markets, in addition to our credit ratings. Disruptions in the capital and credit markets or waning investor sentiment could adversely affect our ability to access short-term and long-term capital. Our access to funds under our CP program is dependent on investor demand for our commercial paper. Disruptions and volatility in the global credit markets could limit the demand for our commercial paper or result in the need to offer higher interest rates to investors, which would result in higher expense and could adversely impact liquidity. Tax rates on dividends may increase, which could increase the cost of equity. The inability to access adequate capital or the increase in cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate the dividend or other discretionary uses of cash. A significant reduction in our liquidity could cause a negative change in our ratings outlook or even a reduction in our credit ratings. This could in turn further limit our access to credit markets and increase our costs of borrowing.

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

We have made, and expect to continue to make, large capital expenditures in order to finance the expansion, upgrading and maintenance of our transmission and distribution systems. We also purchase natural gas for storage. We have made several equity method investments and will continue to pursue other similar investments, all of which are and will be important to our growth and profitability. We fund 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 debt and equity securities. Our dependency on external sources of financing creates the risk that our profits could decrease as a result of higher borrowing costs and that we may not be able to secure external sources of cash necessary to fund our operations and new investments on terms acceptable to us. Volatility in seasonal cash flow requirements, including requirements for our gas supply procurement and risk management programs, may require increased levels of borrowing that could result in non-compliance with the debt-to-equity ratios in our credit facilities as well as cause a credit rating downgrade. Any disruptions in the capital and credit markets could require us to conserve cash until the markets stabilize or until alternative credit arrangements or other funding required for our needs can be secured. Such measures could cause deferral of major capital expenditures, changes in our gas supply procurement program, the reduction or elimination of the dividend payment or other discretionary uses of cash, and could negatively affect our future growth and earnings.

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

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

The cost of providing pension benefits and related funding obligations may increase.

Our costs of providing a 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, changes in these actuarial assumptions, future government regulation, changes in life expectancy and our required or voluntary contributions made to the plan. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund our pension plan, if not offset or mitigated by a decline in our liabilities, 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.

Regulatory Risks

Elevated levels of capital expenditures may weaken our financial position and inhibit customer growth.

We make significant annual capital expenditures for system integrity, infrastructure and maintenance that do not immediately produce revenue. We have the ability to recover these costs either through general rate cases or alternative rate mechanisms approved by state regulatory commissions, such as RSAs and IMRs, that periodically adjust rates to reflect incurred capital expenditures. However, before rates are adjusted, we fund construction through operating cash flows and by accessing short- and long-term capital markets and as a result, we may experience reduced liquidity and deteriorating credit metrics, which may weaken our financial position and could trigger a possible downgrade from the rating agencies. In addition, after these capital costs are reflected in rates, to the extent that rates rise considerably, customers may choose alternative forms of energy to meet their needs. This would reduce our customer growth, which would weaken our financial position by reducing earnings and cash flows.

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

Our regulated utility segment is regulated by the NCUC, the PSCSC and the TRA. These agencies set the rates that we charge our customers for our services. We monitor allowed rates of return and our ability to earn appropriate rates of return based on factors, such as increased operating costs, and initiate general rate proceedings as needed. Our earnings could be negatively impacted if a state regulatory commission were to prohibit us from setting rates that allow for the timely recovery of our costs and a reasonable return, or significantly lowers our allowed return or negatively alters our cost allocation, rate design, cost trackers, including margin decoupling and cost of gas, or prohibits recovery of regulatory assets, including deferred gas costs.

In the normal course of business in the regulatory environment, assets are placed in service before rate cases can be filed that could result in an adjustment of our returns. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we may suffer the negative financial effects of having placed in service assets that do not initially earn our authorized rate of return without the benefit of rate relief, which is commonly referred to as "regulatory lag." Additionally, our capital investment in recent years has been and is projected to remain at higher levels, increasing the risk of cost recovery. All of this may negatively impact our results of operations and earnings.

Rate cases also involve a risk of rate reduction, because once rates have been filed, they are still subject to challenge for their reasonableness by various intervenors. State regulators have approved various mechanisms to stabilize our gas utility margin, including margin decoupling in North Carolina, rate stabilization in South Carolina, and uncollectible gas cost recovery in all states. State regulators have approved other margin stabilizing mechanisms that, for example, allow us to recover any margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may otherwise directly access natural gas supply through their own connection to an interstate pipeline. If regulators decided to discontinue allowing us to use these tariff mechanisms, it would negatively impact our results of operations, financial condition and cash flows. In addition, regulatory authorities also review whether our gas costs are prudent and can disallow the recovery of a portion of our gas costs that we seek to recover from our customers, which would adversely impact earnings.

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.

We are subject to new and existing laws and regulations that may require significant expenditures, significantly increase operating costs, or significant fines or penalties for noncompliance.

Our business and operations are subject to regulation by the FERC, the NCUC, the PSCSC, the TRA, the DOT, the EPA, the CFTC and other agencies, and we are subject to numerous federal and state laws and regulations. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers. For example, while we have implemented an IMR mechanism in North Carolina and Tennessee to recover certain capital expenditures made in compliance with federal and state safety and integrity management laws or regulations, there is a risk that the relevant regulators will disallow some of the expenditures under the IMR mechanism, and that the costs expended in compliance with such laws would not be recoverable through such rate mechanisms (but rather through general rate cases with extended lag). Because the language in some laws and regulations is not prescriptive, there is a risk that our interpretation of these laws and regulations may not be consistent with expectations of regulators. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation. As the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. All of these events could result in a material adverse effect on our business, results of operations or financial condition.

Climate change, carbon neutral or energy efficiency legislation or regulations could increase our operating costs or restrict our market opportunities, negatively affecting our growth, cash flows and earnings.

The federal and/or state governments may enact legislation or regulations that attempt to control or limit the causes of climate change, including greenhouse gas emissions such as carbon dioxide and air emissions regulations that could be expanded to address emissions of methane. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. The focus on climate change could negatively impact the reputation of fossil fuel products or services. The occurrence of these events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas, and impact the competitive position of natural gas and the ability to serve new customers, negatively affecting our growth opportunities, cash flows and earnings.

Changes in federal and/or state fiscal, tax and monetary policy could significantly increase our costs or decrease our cash *flows.*

Changes in federal and/or state fiscal, tax and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods, services and labor. This could increase our expenses and decrease our earnings if

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we are not able to recover such increased costs from our customers. These events may increase our rates to customers and thus may negatively impact customer billings and customer growth. Changes in accounting or tax rules could negatively affect our earnings and cash flows. Any of these events may cause us to increase debt, conserve cash, negatively affect our ability to make capital expenditures to grow the business or require us to reduce or eliminate the dividend or other discretionary uses of cash, and could negatively affect earnings.

Operational Risks

The operation of our gas distribution and transmission activities may be interrupted by accidents, work stoppage, severe weather conditions, including destructive weather patterns, such as hurricanes, tornadoes and floods, pandemic or acts of terrorism and sabotage.

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

We may be unable to attract and retain professional and technical employees, which 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, train, develop and retain a skilled workforce. We are subject to the risk that we will not be able to effectively replace the knowledge and expertise of an aging workforce as those workers retire. Without a properly skilled and experienced workforce, our costs, including productivity and safety costs, costs to replace employees, and costs as a result of errors may increase, and this could negatively impact our earnings.

Cybersecurity attack, acts of cyber-terrorism or failure of technology systems could disrupt our business operations, shut down our facilities or result in the loss or exposure of confidential or sensitive customer, employee or Company information.

We are placing greater reliance on technological tools that support our operations and corporate functions and processes. We may own these tools or have a license to use them, or we may rely on the technological tools of third parties to whom we outsource processes. We use such tools to manage our natural gas distribution and transmission pipeline operations, maintain customer, employee, Company and vendor data, prepare our financial statements, make compliance filings and manage supply chain and other business processes. One or more of these technologies may fail due to physical disruption such as flooding, design defects or human error, or we may be unable to have these technologies supported, updated, expanded or integrated into other technologies. As technology and as our business operations change, we may replace or add systems and tools, and failure to successfully execute on these projects may result in business disruption or loss of data. Additionally, our business operations and information technology systems may be vulnerable to attack by individuals or organizations that could result in disruption to them. In recent years, cybersecurity risks have increased due in part to the increased sophistication and frequency of the attacks.

Disruption or failure of business operations and information technology systems could shut down our facilities or otherwise adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline systems, serve our customers effectively or manage our assets. An attack on or failure of information technology systems could result in the unauthorized release of customer, employee or other confidential or sensitive data. These events could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability, and our operations and financial results could be adversely affected.

Our insurance coverage may not be sufficient.

We currently have general liability, property and cyber insurance in place in amounts that we consider appropriate based on our business risk and best practices in our industry and in general business. Such policies are subject to certain limits and deductibles and include business interruption coverage for limited circumstances. Insurance coverage for risks against which we and others in our industry typically insure may not be available in the future, or may be available but at materially increased costs, reduced coverage or on terms that are not commercially reasonable. Premiums and deductibles may increase substantially. The insurance proceeds received for any loss of, or any damage to, any of our facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be paid in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial position, results of operations and cash flows.

Strategic Risks

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

We are invested in several natural gas related businesses as an equity method investor. The businesses in which we invest are subject to laws, regulations or market conditions, or have risks inherent in their operations, that could adversely affect their performance. Those that are not directly regulated by state or federal regulatory bodies could be subject to adverse market conditions not experienced by our regulated utility segment and our regulated non-utilities segment. We do not control the day to day operations of our equity method investments, and thus the management of these businesses by our partners could adversely impact their performance. We may not be able to fully direct the management and policies of these businesses, and other participants in those relationships may take action contrary to our interests, including making operational decisions that could affect our costs and liabilities related to our investment. In addition, other participants may withdraw from the business, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. The results of operations from those investments may be significantly less or realized significantly later than anticipated. All the above could adversely affect our earnings from or return on our investment in these businesses. We could make future equity method investments, acquisitions, or other business arrangements involving regulated or unregulated businesses as a minority or majority owner, with the similar potential to adversely affect our earnings from or return of our investment in those businesses.

Risks Related to the Proposed Acquisition by Duke Energy

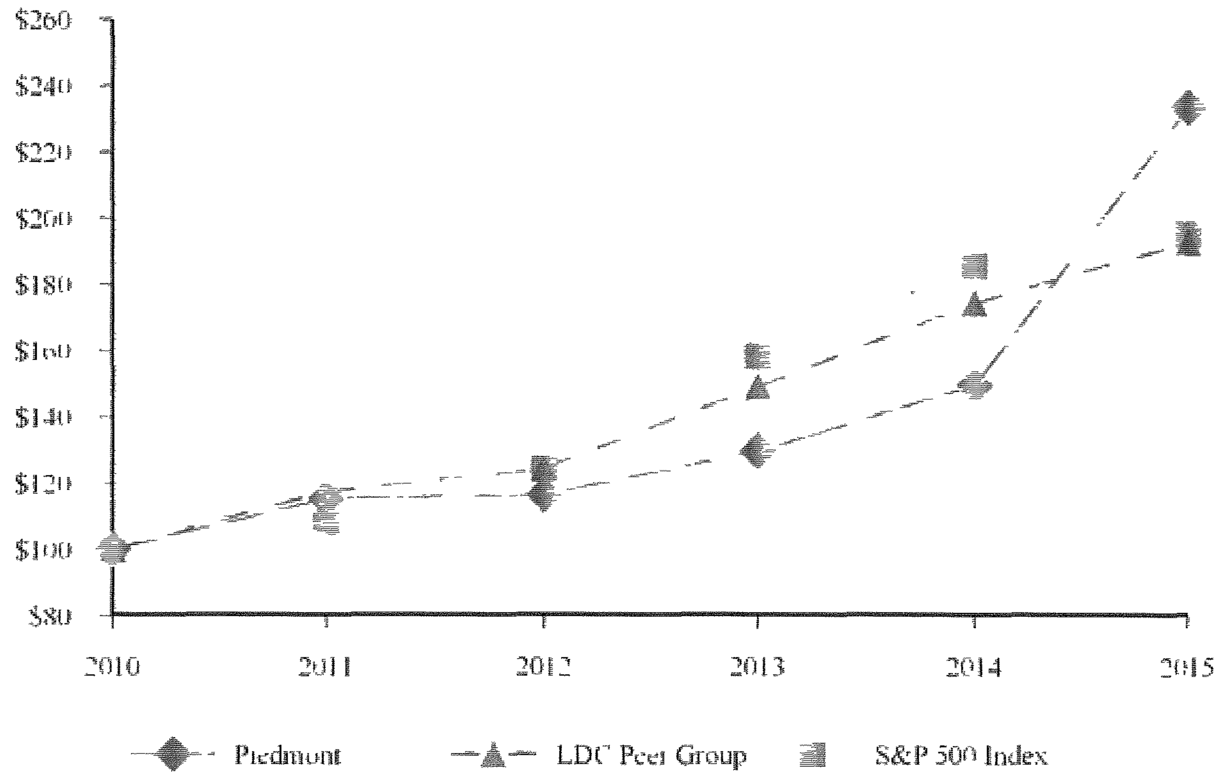
The Acquisition is subject to receipt of consent or approval from our shareholders and various governmental entities that could delay or prevent the completion of the Acquisition or, in order to receive such consent or approval, the governmental entities may impose restrictions or conditions that could have a material adverse effect on the combined company or that could cause the companies to terminate the transaction.

Completion of the Acquisition is contingent upon, among other things, satisfaction or waiver of specified closing conditions, including (i) the approval of the Acquisition by the holders of a majority of the outstanding shares of Piedmont's common stock, (ii) the receipt of regulatory approvals required to consummate the Acquisition, including approval from the NCUC, (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (Hart-Scott-Rodino Act), (iv) the absence of any law, statute, ordinance, code, rule, regulation, ruling, decree, judgment, injunction or order of a governmental authority that prohibits the consummation of the Acquisition, and (v) other customary closing conditions. If the Acquisition is consummated, holders of shares of Piedmont common stock will have no on-going equity in the surviving corporation, will cease to participate in Piedmont's future earnings and growth and will not benefit from any future increases in the value of Piedmont.

We may not receive the required statutory approvals and other clearances for the Acquisition, or we may not receive them in a timely manner. If such approvals and clearances are received, they may impose terms, conditions or restrictions (i) that cause a failure of the closing conditions set forth in the Merger Agreement, which could permit us or Duke Energy to terminate the Merger Agreement or (ii) that could reasonably be expected to have a detrimental impact on the combined company following completion of the Acquisition. A substantial delay in obtaining the required authorizations, approvals or consents or the imposition of unfavorable terms, conditions or restrictions contained in such authorizations, approvals or consents could prevent the completion of the Acquisition.

Even after the expiration of the waiting period under the Hart-Scott-Rodino Act, governmental authorities could seek to block or challenge the Acquisition as they deem necessary or desirable in the public interest.

Comparisons of Five-Year Cumulative Total Returns
Values of $100 Invested as of October 31, 2010



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

	2010	2011	2012	2013	2014	2015
Piedmont	$ 100	$ 115	$ 117	$ 130	$ 150	$ 234
LDC Peer Group	100	118	125	149	175	193
S&P 500 Index	100	108	125	158	186	195

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Item 6. Selected Financial Data

The following table provides selected financial data for the years ended October 31, 2011 through 2015.

In thousands, except per share amounts	**2015**	2014	2013	2012	2011
Operating Revenues	**$ 1,371,718**	$ 1,469,988	$ 1,278,229	$ 1,122,780	$ 1,433,905
Margin (operating revenues less cost of gas)	**$ 727,294**	$ 690,208	$ 621,490	$ 575,446	$ 573,639
Net Income	**$ 137,011**	$ 143,801	$ 134,417	$ 119,847	$ 113,568
Earnings per Share of Common Stock:					
Basic	**$ 1.74**	$ 1.85	$ 1.80	$ 1.67	$ 1.58
Diluted	**$ 1.73**	$ 1.84	$ 1.78	$ 1.66	$ 1.57
Cash Dividends per Share of Common Stock	**$ 1.31**	$ 1.27	$ 1.23	$ 1.19	$ 1.15
Total Assets (1)	**$ 5,110,750**	$ 4,774,307	$ 4,360,277	$ 3,764,144	$ 3,238,780
Long-Term Debt (less current maturities) (1)	**$ 1,523,677**	$ 1,414,484	$ 1,166,525	$ 969,205	$ 671,239

(1) Total assets and long-term debt for the years 2011 through 2014 have been adjusted to reflect the netting of debt issuance costs with its debt carrying value in accordance with the 2015 adoption of new accounting guidance related to this balance sheet presentation.

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

Forward-Looking Statements

This report, including the documents incorporated by reference and other documents that 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 from 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 the following, as well as those discussed in Item 1A. Risk Factors, including those related to the Acquisition by Duke Energy that is more fully discussed in Note 2 to the consolidated financial statements in this Form 10-K:

- Economic conditions in our markets.
- Wholesale price of natural gas.
- Availability of adequate interstate pipeline transportation capacity and natural gas supply.
- Regulatory actions at the state level that impact our ability to earn a reasonable rate of return and fully recover our operating costs on a timely basis.
- Competition from other companies that supply energy.
- Changes in the regional economies, politics, regulations and weather patterns of the three states in which our operations are concentrated.
- Costs of complying or effect of noncompliance with state and federal laws and regulations that are applicable to us.
- Effect of climate change, carbon neutral or energy efficiency legislation or regulations on costs and market opportunities.
- Weather conditions.
- Operational interruptions to our gas distribution and transmission activities.
- Inability to complete necessary or desirable pipeline expansion or infrastructure development projects.
- Elevated levels of capital expenditures.
- Changes to our credit ratings.
- Availability and cost of capital.
- Federal and state fiscal, tax and monetary policies.

- Ability to generate sufficient cash flows to meet all our cash needs.
- Ability to satisfy all of our outstanding debt obligations.
- Ability of counterparties to meet their obligations to us.
- Costs of providing pension benefits.
- Earnings from the joint venture businesses in which we invest.
- Ability to attract and retain professional and technical employees.
- Cybersecurity breaches or failure of technology systems.

- Ability to obtain and maintain sufficient insurance.
- Change in number of outstanding shares.
- Certain risks and uncertainties associated with the Acquisition, including, without limitation:
    - the possibility that the Acquisition does not close due to the failure to satisfy the closing conditions, including, but not limited to, a failure of shareholders to approve the Acquisition or a failure to obtain the required regulatory approvals;
    - delays caused by the required regulatory approvals, which may delay the Acquisition or cause the companies to abandon the transaction;
    - uncertainties and disruptions caused by the Acquisition that make it more difficult to maintain our business and operational relationships as well as maintain our relationships with employees, suppliers or customers, and the risk that unexpected costs will be incurred during this process;
    - the diversion of management time on Acquisition-related issues, and;
    - pending or future shareholder suits could delay or prevent the closing of the Acquisition or otherwise adversely impact our business and operations.

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 place undue reliance on these forward-looking statements when making investment decisions. When used in our documents or oral presentations, the words "expect," "believe," "project," "anticipate," "intend," "may," "should," "could," "assume," "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 based on information available to us 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. 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 SEC.

Overview

Piedmont Natural Gas Company, Inc. (Piedmont), 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 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, regulated interstate natural gas transportation and storage and regulated intrastate natural gas transportation businesses.

We operate with three reportable business segments, regulated utility, regulated non-utility activities and unregulated non-utility activities, with the regulated utility segment being the largest. Our utility operations are regulated by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina and the Tennessee Regulatory Authority as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. The NCUC also regulates us as to the issuance of long-term debt and equity securities. Factors critical to the success of the regulated utility segment include operating a safe and reliable natural gas distribution system and the ability to recover the costs and expenses of the business in the rates charged to customers. The regulated non-utility activities segment consists of our equity method investments in joint venture regulated energy-related pipeline and storage businesses that are held by our wholly-owned subsidiaries. The unregulated non-utility activities segment consists primarily of our equity method investment in SouthStar Energy Services, LLC (SouthStar) that is held by a wholly-owned subsidiary. For further information on equity method investments and business segments, see Note 13 and Note 15, respectively, to the consolidated financial statements in this Form 10-K.

Gas Deliveries, Customers, Weather Statistics and Number of Employees

				Percent Change	
	2015	2014	2013	**2015 vs. 2014**	2014 vs. 2013
Deliveries in Dekatherms (in thousands):					
Residential	**61,004**	61,782	55,283	**(1.3)%**	11.8 %
Commercial	**44,616**	44,259	39,602	**0.8 %**	11.8 %
Industrial	**96,380**	95,780	95,019	**0.6 %**	0.8 %
Power Generation	**262,161**	201,707	190,862	**30.0 %**	5.7 %
For Resale	**7,362**	7,174	6,834	**2.6 %**	5.0 %
Throughput	**471,523**	410,702	387,600	**14.8 %**	6.0 %
Secondary Market Volumes	**30,759**	20,516	41,605	**49.9 %**	(50.7)%
Customers Billed (at period end)	**1,011,959**	992,551	979,909	**2.0 %**	1.3 %
Gross Residential, Commercial and Industrial Customer Additions	**17,017**	16,251	14,293	**4.7 %**	13.7 %
Degree Days					
Actual	**3,449**	3,543	3,336	**(2.7)%**	6.2 %
Normal	**3,257**	3,265	3,276	**(0.2)%**	(0.3)%
Percent colder than normal	**5.9%**	8.5%	1.8%	**n/a**	n/a
Number of Employees (at period end)	**1,943**	1,879	1,795	**3.4 %**	4.7 %

Financial Performance – Fiscal 2015 Compared with Fiscal 2014

Our 2015 net income decreased 5%. Margin increased 5% due to rate adjustments to customers through integrity management riders (IMRs) and new rates effective January 1, 2014 in North Carolina under a rate case settlement, and overall customer growth, partially offset by lower margin sales from secondary market transactions. Operations and maintenance (O&M) expenses and depreciation expense increased 9% and 8%, respectively. The increase in O&M expenses was related to increases in contract labor, payroll, employee benefits and regulatory expenses, including direct and indirect Acquisition-related expenses of $15.8 million, partially offset by a decrease in bad debt expense. Depreciation was higher due to increases in plant in service. General taxes increased 13% primarily due to increased state property and franchise taxes. Other Income (Expense), net of tax, increased 11% primarily due to an increase in income from equity method investments and a write-off in the prior year of a cost-basis investment. Utility interest charges increased 26% as a result of increases in long-term debt outstanding and a decrease in capitalized interest recorded as income.

Business Summary – Fiscal 2015

Our fiscal 2015 performance reflects execution of our long-term business strategy that focuses on safety and growth in our markets, favorable changes in state regulation with new rates and IMRs, and secondary market activity. As discussed above, financial performance was solid for the year with increased earnings, excluding Acquisition-related expenses, and an increase in our dividend rate per share to our investors.

Financial Strength and Flexibility – In order to prudently fund our investment in growth and our ongoing capital needs, we executed our financing programs to optimize and reduce our cost of capital, preserve our liquidity and strong balance sheet and protect our high quality credit ratings with a goal of maintaining a total debt to capital ratio between 50% and 60%. In January 2015, we established an at-the-market (ATM) equity sales program, including a forward sales component, under our effective shelf registration statement. The timing and volume of sales under this program cannot be predicted with certainty and may be affected by factors outside our control, but will not exceed an aggregate of $170 million from the period beginning January 2015 through the end of fiscal 2016. We continue to rely on our commercial paper (CP) program to meet our short-term liquidity needs.. We accomplished the following in fiscal year 2015:

- In September 2015, we issued $150 million of ten-year, unsecured senior notes, receiving net proceeds of $148.9 million.

- In October 2015, we issued 1.5 million shares under our ATM equity sales program under the forward sales agreements (FSAs), receiving proceeds of $54.1 million.

For further information on these transactions, see Note 5 and Note 7 to the consolidated financial statements in this Form 10-K and the following discussion of "Cash Flows from Financing Activities."

Managing Gas Supplies and Prices – Our gas supply acquisition strategy is regularly reviewed and adjusted to ensure that we have adequate and reliable supplies of competitively priced natural gas to meet the needs of our utility customers. In order to provide additional diversification, reliability and gas cost benefits to our customers, we have long-term supply and capacity contracts to buy and transport more of our gas supplies from the Marcellus shale basin in Pennsylvania for our markets in the Carolinas. These new long-term sources of supply became available in late 2015 with the partial completion of the Williams – Transco Leidy Southeast expansion project and its Virginia Southside expansion project. In October 2014, we signed a long-term pipeline capacity precedent agreement under the Atlantic Coast Pipeline, LLC (ACP) project to source additional gas supplies from diverse gas supply basins in central West Virginia that are anticipated to be available for the winter 2018 – 2019 season.

Customer Growth – We have added increasing numbers of customers in our service areas each year over our last three fiscal years. Affordable and stable wholesale natural gas costs continued to favorably position natural gas relative to other energy sources. Continued improvement in economic conditions and targeted marketing programs on the benefits of natural gas resulted in growth in both the residential new construction and commercial markets. Growth in residential conversion and industrial markets decreased slightly, reflecting a longer sales cycle for conversions and a decline in readily available opportunities for industrial conversions. Overall, total residential and commercial customers increased in 2015 compared to 2014 and 2013, as presented below.

				Percent Change	
	2015	2014	2013	**2015 vs. 2014**	2014 vs. 2013
Residential new home construction	**12,436**	11,659	10,299	**6.7 %**	13.2 %
Residential conversion	**2,789**	2,814	2,463	**(0.9)%**	14.3 %
Commercial	**1,780**	1,763	1,512	**1.0 %**	16.6 %
Industrial	**12**	15	19	**(20.0)%**	(21.1)%
Total new customers	**17,017**	16,251	14,293	**4.7 %**	13.7 %

Overall, total net customers billed increased 2% as compared to 2014.

Capital Expenditures – We continued to execute our capital expansion and improvement programs that will provide benefits to our customers through safe and reliable natural gas service while providing our shareholders a fair and reasonable return on invested capital. Our capital expenditures are driven by pipeline integrity, safety and compliance programs, investments for customer growth, system infrastructure and technology, including a comprehensive work and asset management system.

With significant capital costs incurred under our ongoing system integrity programs, we have IMR regulatory mechanisms in North Carolina and Tennessee to separately track and recover certain costs associated with capital expenditures incurred to comply with federal pipeline safety and integrity programs, as well as additional state safety and integrity requirements in Tennessee. The IMR orders by jurisdiction and the amount reflected in "Operating Revenues" in the Consolidated Statements of Comprehensive Income for 2015 is summarized below:

In millions	North Carolina		Tennessee
Incremental annual margin revenue - 2014 IMR filing	$ 1.0	(1)	$ 13.1
Incremental annual margin revenue - 2015 IMR filing	24.4	(1)	6.5
Total cumulative incremental annual margin revenue in 2015 (2)	$ 25.4	(1)	$ 19.6
Amounts recorded as revenues during fiscal year 2015	**$ 17.1**		**$ 18.2**

(1) Amounts are adjusted to reflect the 2015 IMR settlement agreement approved by the NCUC in November. For further information on the IMR settlement agreement, see Note 3 to the consolidated financial statements in this Form 10-K.

(2) IMR recovery period in both jurisdictions does not align with our fiscal year. For further information on those periods, see Note 3 to the consolidated financial statements in this Form 10-K.

We completed pipeline expansion projects in recent years that provide natural gas delivery service to new power generation facilities in our market area. We currently provide service to 25 power generation customer accounts. See the discussion of our forecasted capital investments in "Cash Flows from Investing Activities" in this Form 10-K.

Sustainable Business Practices – In February 2015, the winter weather throughout our service area was the coldest in 37 years. During this month, we experienced a record customer volume sendout for our 65-year history, with February 19, 2015 as a new, single-day volume sendout record of 2.6 million dekatherms. Our ability to provide safe and reliable natural gas service under these operating conditions was due to our ongoing investments in our pipeline delivery system through our system expansion and pipeline integrity management programs. Our review and implementation of our gas supply acquisition strategy ensures that we have adequate and reliable supplies to meet the peak day needs of our utility customers. We evaluate ongoing cold weather conditions and corresponding customer consumption patterns, as well as historical winter weather over the past 40 years, in developing our peak day requirements.

Equity Method Investments – Our investments in complementary energy-related businesses continue to be an attractive way to generate earnings growth and long-term shareholder returns. We are a member of two ventures that propose to construct interstate natural gas pipelines, subject to the jurisdiction of the Federal Energy Regulatory Commission. We are a 24% equity member of Constitution Pipeline Company LLC (Constitution) that plans to transport natural gas produced from the Marcellus shale basin in Pennsylvania to northeast markets. We are a 10% equity member of ACP that plans to transport diverse gas supplies into southeastern markets. The project would also require us to expand our utility natural gas delivery system in eastern North Carolina to provide redelivery of ACP volumes to retail natural gas markets. Having a second major interstate pipeline in the state will enhance the reliability and diversity of gas supplies to our Carolinas market area. For further information on our anticipated contributions for these project costs, anticipated in-service dates and contributions made to date, see "Cash Flows from Investing Activities" in this Form 10-K. For further information on equity method investments and business segments, see Note 13 and Note 15, respectively, to the consolidated financial statements in this Form 10-K.

Proposed Acquisition by Duke Energy – On October 24, 2015, we entered into a Merger Agreement with Duke Energy and Forest Subsidiary, Inc. (Merger Sub), a new wholly owned subsidiary of Duke Energy. The Merger Agreement provides for the Acquisition by merging the Merger Sub with and into Piedmont, with Piedmont surviving as a wholly owned subsidiary of Duke Energy. At the effective time of the Acquisition, subject to receipt of required shareholder and regulatory approvals and meeting specified customary closing conditions, each share of Piedmont common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $60 in cash per share, without interest, less any applicable withholding taxes. For further information on the Acquisition, see Item 1A. Risk Factors, "Forward Looking Statements" in Item 7, and Note 2 and Note 16 to the consolidated financial statements in this Form 10-K. In the Merger Agreement, we agreed to covenants affecting the conduct of our business between the date of the Merger Agreement and the effective date of the Acquisition.

On November 6, 2015, Thomas E. Skains, Chairman, President and Chief Executive Officer of Piedmont, notified our Board of Directors and Duke Energy of his intent to terminate his employment and retire from Piedmont effective, and contingent, upon the closing of the Acquisition.

On December 14, 2015, we filed a definitive proxy statement with the SEC to notify our shareholders of a special meeting to be held on January 22, 2016 to vote on the Acquisition of Piedmont by Duke Energy. We and Duke Energy have filed notification and report forms under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. In December 2015, the Federal Trade Commission granted antitrust approval of the Acquisition.

In accordance with the SouthStar limited liability company agreement, upon the announcement of the Acquisition, we delivered a notice of change of control to Georgia Natural Gas Company (GNGC). On December 9, 2015, GNGC delivered to us a written notice electing to purchase our entire 15% interest in SouthStar. GNGC's election to purchase our entire 15% interest in SouthStar is subject to and effective with the consummation of the Acquisition.

Strategy and Focus Areas

Our long-term strategic directives shape our annual business objectives and focus on our customers, our communities, our employees and our shareholders. They also reflect what we believe are the inherent advantages of natural gas compared to other types of energy. Our seven foundational strategic priorities are as follows:

- Promote the benefits of natural gas,
- Expand our core natural gas and complementary energy-related businesses to enhance shareholder value,
- Be the energy service provider of choice,
- Achieve excellence in customer service every time,
- Preserve financial strength and flexibility,
- Execute sustainable business practices, and
- Enhance our healthy, high performance culture.

With a continued focus on these priorities, we believe we will enhance long-term shareholder value. For a full discussion of our strategy and focus areas, see Item 1. Business in this Form 10-K.

Additional information on operating results for the years ended October 31, 2015, 2014 and 2013 follows.

Results of Operations

Operating Revenues

Changes in operating revenues for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Operating Revenue - Increase (Decrease)

In millions	**2015 vs. 2014**	2014 vs. 2013
Residential and commercial customers	**$ (85.2)**	$ 201.5
Industrial customers	**(9.6)**	1.4
Power generation customers	**(0.3)**	21.8
Secondary market	**(35.2)**	5.4
Margin decoupling mechanism	**6.4**	(39.4)
WNA mechanisms	**1.6**	(11.4)
IMR mechanisms	**24.6**	10.7
Other	**(0.6)**	1.8
Total	**$ (98.3)**	$ 191.8

2015 compared to 2014:

- Residential and commercial customers – the decrease is primarily due to lower wholesale gas costs passed through to customers and lower consumption from warmer weather, slightly offset by customer growth.
- Industrial customers – the decrease is primarily due to lower wholesale gas costs passed through to customers and decreased transportation revenues, slightly offset by increased revenue on special contracts.
- Power generation customers – the decrease is primarily due to certain annual contract rate adjustments.
- Secondary market – the decrease is due to lower margin sales prices. Secondary market transactions consist of off-system sales and capacity release and asset management arrangements that are part of our regulatory gas supply

management program with regulatory-approved sharing mechanisms between our utility customers and our shareholders.

- Margin decoupling mechanism – the increase is primarily related to warmer weather in North Carolina. As discussed in "Financial Condition and Liquidity," the margin decoupling mechanism in North Carolina adjusts for variations in residential and commercial use per customer, including those due to weather and conservation.
- Weather normalization adjustment (WNA) mechanisms – the increase is due to warmer weather in South Carolina and Tennessee, as compared to the prior period. As discussed in "Financial Condition and Liquidity," the WNA mechanisms partially offset the impact of colder- or warmer-than-normal weather on bills rendered.
- IMR mechanisms – the increase is due to incremental IMR rate adjustments in North Carolina and Tennessee. The North Carolina and Tennessee IMR mechanisms were effective February 1, 2014 and January 1, 2014, respectively.

2014 compared to 2013:

- Residential and commercial customers – the increase is primarily due to higher consumption from colder weather, higher wholesale gas costs passed through to customers and customer growth.
- Industrial customers – the increase is primarily due to higher consumption from colder weather and higher wholesale gas costs passed through to customers, slightly offset by decreased transportation revenues.
- Power generation customers – the increase is primarily due to increased transportation services.
- Secondary market – the increase is due to higher margin sales related to sustained colder-than-normal weather and increased wholesale market volatility.
- Margin decoupling mechanism – the decrease is primarily related to colder weather in North Carolina.
- WNA mechanisms – the decrease is due to colder weather in South Carolina and Tennessee.
- IMR mechanisms – the increase is due to the IMR rate adjustments in Tennessee effective January 1, 2014 and North Carolina effective February 1, 2014.

Cost of Gas

Changes in cost of gas for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Cost of Gas - Increase (Decrease)

In millions	2015 vs. 2014	2014 vs. 2013
Commodity gas costs passed through to sales customers	**$ (125.8)**	$ 137.5
Commodity gas costs in secondary market transactions	**(31.0)**	(11.0)
Pipeline demand charges	**(13.1)**	(7.1)
Regulatory approved gas cost mechanisms	**34.5**	3.6
Total	**$ (135.4)**	$ 123.0

2015 compared to 2014:

- Commodity gas costs passed through to sales customers – the decrease is primarily due to lower wholesale gas costs passed through to sales customers, slightly offset by customer growth.
- Commodity gas costs in secondary market transactions – the decrease is primarily due to lower average wholesale gas costs, slightly offset by increased volumes.
- Pipeline demand charges – the decrease is primarily due to increased capacity release revenues and decreased demand costs, slightly offset by decreased asset manager payments.
- Regulatory approved gas cost mechanisms – the increase is primarily due to an increase in commodity cost and demand true-ups, partially offset by other regulatory mechanisms.

2014 compared to 2013:

- Commodity gas costs passed through to sales customers – the increase is primarily due to higher volumes sold due to colder weather and higher wholesale gas costs passed through to sales customers.
- Commodity gas costs in secondary market transactions – the decrease is primarily due to decreased activity, partially offset by higher average wholesale gas costs.

- Pipeline demand charges – the decrease is due to decreased demand costs and increased capacity release revenues, slightly offset by decreased asset manager payments.

- Regulatory approved gas cost mechanisms – the increase is primarily due to demand cost true-ups, slightly offset by other regulatory mechanisms.

In all three states, we are authorized to recover from customers all prudently incurred gas costs. Charges 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 in current "Regulatory assets" or current "Regulatory liabilities" in the Consolidated Balance Sheets and are added to or deducted from cost of gas. For the amounts included in "Amounts due from customers" or "Amounts due to customers," see Note 3 to the consolidated financial statements in this Form 10-K.

Margin

Margin, rather than revenues, is used by management to evaluate utility operations due to the regulatory pass through of changes in wholesale commodity gas costs. Our utility margin is defined as natural gas revenues less natural gas commodity costs and fixed gas costs for transportation and storage capacity. It is the component of our revenues that is established in general rate cases and is designed to cover our utility operating expenses and our return of and on our utility capital investments and related taxes. Our commodity gas costs accounted for 35% of revenues for the year ended October 31, 2015 and 41% for the years ended October 31, 2014 and 2013. Our pipeline transportation and storage costs accounted for 10% for the years ended October 31, 2015 and 2014 and 12% for the year ended October 31, 2013.

In general rate proceedings, state regulatory commissions authorize us to recover our margin in our monthly fixed demand charges and on each unit of gas delivered under our generally applicable sales and transportation tariffs and special service contracts. We negotiate special service contracts with some industrial customers that may include the use of volumetric rates with minimum margin commitments and fixed monthly demand charges. These individually negotiated agreements are subject to review and approval by the applicable state regulatory commission and allow us to make an economic extension or expansion of natural gas service to larger industrial customers.

Our utility margin is also impacted by certain regulatory mechanisms as defined elsewhere in this document. These regulatory mechanisms by jurisdiction are presented below.

Regulatory Mechanism	North Carolina	South Carolina	Tennessee
WNA mechanism*		X	X
Margin decoupling mechanism *	X		
Natural gas rate stabilization mechanism		X	
Secondary market programs **	X	X	X
Incentive plan for gas supply **			X
IMR mechanism	X		X
Negotiated margin loss treatment	X	X	
Uncollectible gas cost recovery	X	X	X

* Residential and commercial customers only.

** In all jurisdictions, we retain 25% of secondary market margins generated through off-system sales and capacity release activity, with 75% credited to customers. Our share of net gains or losses in Tennessee is subject to an annual cap of $1.6 million.

Changes in margin for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Margin - Increase (Decrease)

In millions	**2015 vs. 2014**	2014 vs. 2013
Residential and commercial customers	**$ 39.9**	$ 31.2
Industrial customers	**2.7**	—

Power generation customers	**(0.3)**	21.3
Secondary market activity	**(4.3)**	16.4
Net gas cost adjustments	**(0.9)**	(0.2)
Total	**$ 37.1**	$ 68.7

2015 compared to 2014:

- Residential and commercial customers – the increase is primarily due to incremental IMR rate adjustments discussed above, as well as the general rate increase in North Carolina effective January 1, 2014, and customer growth in all three states, partially offset by decreased volumes delivered in South Carolina and Tennessee due to warmer weather.
- Industrial customers – the increase is due to incremental IMR rate adjustments discussed above, increased margin on special contracts and higher consumption in the industrial market.
- Power generation customers – the decrease is primarily due to certain annual contract rate adjustments.
- Secondary market activity – the decrease is primarily due to lower margin sales.

2014 compared to 2013:

- Residential and commercial customers – the increase is primarily due to the general rate increase in North Carolina effective January 1, 2014, the IMR rate adjustments discussed above, customer growth in all three states and increased volumes delivered in South Carolina and Tennessee due to colder weather.
- Power generation customers – the increase is primarily due to increased transportation services.
- Secondary market activity – the increase is primarily due to higher margin sales related to increased wholesale market volatility and sustained colder-than-normal weather.

Operations and Maintenance Expenses

Changes in O&M expenses for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Operations and Maintenance Expenses - Increase (Decrease)

In millions	**2015 vs. 2014**	2014 vs. 2013
Contract labor	**$ 13.4**	$ 1.9
Payroll	**7.9**	9.6
Employee benefits	**2.5**	(0.3)
Regulatory	**1.0**	4.2
Bad debt	**(1.8)**	2.1
Other	**0.6**	0.3
Total	**$ 23.6**	$ 17.8

2015 compared to 2014:

- Contract labor – the increase is primarily due to $8.6 million of expenses related to the Acquisition, increased process improvement projects and pipeline integrity maintenance and safety programs.
- Payroll – the increase is primarily due to additional employees, higher incentive plan accruals of $7.2 million from a higher stock price at October 31 related to the announcement of the Acquisition and employee overtime.
- Employee Benefits – the increase is primarily due to a lower regulatory pension deferral in Tennessee in the current period related to lower funding of the defined benefit plan in 2015 versus 2014.
- Regulatory – the increase is primarily due increased amortization of regulatory assets with approved amortization amounts established in the North Carolina general rate proceeding, effective January 1, 2014.
- Bad debt – the decrease is primarily due lower projected charge-offs than the prior period.

2014 compared to 2013:

- Contract labor – the increase is primarily due to increased call volume and collection efforts for customer receivables resulting from the colder winter, increased process improvement projects and pipeline integrity maintenance and safety programs.

- Payroll – the increase is primarily due to additional employees, employee overtime because of colder-than-normal winter weather and incentive plan accruals.

- Regulatory – the increase is primarily due to increased amortization of regulatory assets with approved amortization amounts established in the North Carolina general rate proceeding, effective January 1, 2014, and an increase in the North Carolina regulatory fee due to increased revenues.
- Bad debt – the increase is primarily due to a higher level of net charge-offs from customer receivables due to the colder weather experienced this past winter and increased accruals to reflect higher aging receivables.

Depreciation

Depreciation expense increased from $112.2 million to $128.7 million over the three-year period 2013 to 2015 primarily due to increases in plant in service, particularly related to major additions to serve new power generation customers and transmission integrity investments.

General Taxes

Changes in general taxes for 2015 and 2014 compared with the same prior periods are presented below.

Changes in General Taxes - Increase (Decrease)

In millions	**2015 vs. 2014**	2014 vs. 2013
Property taxes	**$ 3.1**	$ 1.5
Franchise taxes	**1.3**	0.9
Other	**0.4**	0.3
Total	**$ 4.8**	$ 2.7

2015 compared with 2014:

- Property taxes – the increase is primarily due to increases in property.
- Franchise taxes – the increase is primarily due to changes in North Carolina tax laws and increases in property.

2014 compared with 2013:

- Property taxes – the increase is primarily due to increases in property.
- Franchise taxes – the increase is primarily due to increases in property.

Other Income (Expense)

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

Changes in Other Income (Expense) for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Other Income (Expense) - Increase (Decrease) to Income

In millions	2015 vs. 2014	2014 vs. 2013
Income from equity method investments:		
Constitution	$ 3.4	$ 1.7
SouthStar	(1.0)	5.0
Other	(0.7)	—
Total	1.7	6.7
Non-operating income	1.3	(1.0)
Non-operating expense	0.6	0.8
Income Taxes	(1.6)	(3.0)
Total	$ 2.0	$ 3.5

2015 compared with 2014:

- Income from equity method investments from Constitution – the increase is primarily due to higher capitalized interest associated with increased capital expenditures on the project.
- Income from equity method investments from SouthStar – the decrease is primarily due to a lower value of hedged derivatives and less usage in Georgia and Illinois due to warmer weather, partially offset by favorable margins in Georgia, Illinois and Ohio.
- Non-operating income – the increase is primarily due to the $2 million write-off in 2014 of an investment that was accounted for on the cost basis as discussed below.

2014 compared with 2013:

- Income from equity method investments from Constitution – the increase is primarily due to higher capitalized interest associated with increased capital expenditures on the project.
- Income from equity method investments from SouthStar – the increase is primarily due to the expansion of the business into Illinois markets beginning in September 2013, and favorable weather and customer usage in Georgia, partially offset by higher general and administrative expenses. For further information on the contribution of the Illinois business to SouthStar and our cash contribution in our equity method investment, see Note 13 to the consolidated financial statements in this Form 10-K.
- Non-operating income – the decrease is primarily due to a $2 million write-off of an investment that we accounted for on the cost basis. This investment was presented in "Other noncurrent assets" in "Noncurrent Assets" in the Consolidated Balance Sheets.

Utility Interest Charges

Changes in utility interest charges for 2015 and 2014 compared with the same prior periods are presented below.

Changes in Utility Interest Charges - Increase (Decrease)

In millions	2015 vs. 2014	2014 vs. 2013
Interest expense on long-term debt	$ 9.1	$ 7.4
Borrowed AFUDC	5.3	14.5
Regulatory interest expense, net	(0.5)	8.1
Other	—	(0.3)
Total	$ 13.9	$ 29.7

2015 compared to 2014:

- Interest expense on long-term debt – the increase is primarily due to higher amounts of debt outstanding in the current period.
- Borrowed allowance for funds used during construction (AFUDC) – the increase is due to a decrease in capitalized interest on a lower base of construction expenditures in the current period resulting from the timing of projects being placed into service.

2014 compared to 2013:

- Interest expense on long-term debt – the increase is primarily due to higher amounts of debt outstanding in the current period.
- Borrowed AFUDC – the increase is due to a decrease in capitalized interest on a lower base of construction expenditures in the current period resulting from the timing of projects being placed into service.
- Regulatory interest expense, net – the increase is primarily due to the recording of interest expense on amounts due to customers compared with the recording of interest income in the prior year on amounts due from customers.

Financial Condition and Liquidity

Our financial strategy has continued to focus on maintaining a strong balance sheet, ensuring sufficient cash resources and daily liquidity, accessing capital markets at favorable times when needed, managing critical business risks, and maintaining a balanced capital structure through the issuance of equity or long-term debt securities or the repurchase of our equity securities. The need for long-term capital is driven by the level of and timing of capital expenditures and long-term debt maturities. Our issuance of long-term debt and equity securities is subject to regulation by the NCUC.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to completion of the Acquisition. Among other restrictions, the Merger Agreement limits, beyond previously budgeted and planned amounts and allowed exceptions, our total capital spending, limits the extent to which we can obtain financing through long-term debt and equity, and caps our cash dividend to no more than the current annual per share dividend plus an increase of not more than $.04 per fiscal year, with record dates and payment dates consistent with our current dividend practices. At this time, as a result of the Acquisition, we do not anticipate modifying our 2016 strategy discussed below and do not expect a significant impact on our cash requirements and sources of liquidity.

For information on the issuance of long-term debt and equity securities, see Note 5 and Note 7, respectively, to the consolidated financial statements in this Form 10-K.

To meet our capital and liquidity requirements outside of the long-term capital markets, we rely on certain resources, including cash flows from operating activities, cash generated from our investments in joint ventures and short-term debt. Operating activities primarily provide the liquidity to fund our working capital, a portion of our capital expenditures and other cash needs. We rely on short-term debt together with long-term capital markets to provide a significant source of liquidity to meet operating requirements that are not satisfied by internally generated cash flows. Currently, cash flows from operations are not adequate to finance the full cost of planned investments in customer growth, pipeline integrity programs, system infrastructure and contributions to our joint ventures.

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

We believe that the capacity of short-term credit available to us under our revolving syndicated credit facility and our CP program and the issuance of long-term debt and equity securities, together with cash provided by operating activities, will continue to allow us to meet our needs for working capital, capital expenditures, investments in joint ventures, anticipated debt redemptions, dividend payments, employee benefit plan contributions and other cash needs. Our ability to satisfy all of these requirements is dependent upon our future operating performance and other factors, some of which we are not able to control. These factors include prevailing economic conditions, regulatory changes, the price and demand for natural gas and operational risks, among others. Liquidity has been enhanced by reduced tax payments due to the generation of federal net operating loss (NOL) carryforwards resulting from bonus depreciation, as well as the ability to recover and earn on investments in infrastructure related to our pipeline integrity programs through IMRs in North Carolina and Tennessee. For further information on bonus depreciation, see the following discussion of "Cash Flows from Operating Activities" in this Form 10-K.

Short-Term Debt. We have an $850 million five-year revolving syndicated credit facility that expires in October 2017. We pay an annual fee of $35,000 plus 8.5 basis points for any unused amount. The five-year revolving syndicated credit facility contains normal and customary financial covenants.

On December 14, 2015, we entered into an agreement with the lenders under our existing $850 million five-year revolving syndicated credit facility to amend and extend the facility. The amended facility has substantially similar terms to our existing facility and has an option to request an expansion of financing commitments by an additional $200 million. The amended facility extended the maturity of our facility to December 14, 2020. The amended facility expressly permits the Acquisition by Duke Energy. The CP program will continue to be backstopped by the new credit facility.

We have an $850 million unsecured CP program that is backstopped by the revolving syndicated credit facility. The amounts outstanding under the revolving syndicated credit facility and the CP program, either individually or in the aggregate, cannot exceed $850 million. The notes issued under the CP program may have maturities not to exceed 397 days from the date of issuance. Any borrowings under the CP program rank equally with our other unsecured debt.

We did not have any borrowings under the revolving syndicated credit facility for the year ended October 31, 2015. Highlights for our short-term debt under our CP program as of October 31, 2015 and 2014 and for the quarter and year ended October 31, 2015 and 2014 are presented below.

In thousands		2015
End of period (October 31, 2015):		
Amount outstanding	$	**340,000**
Weighted average interest rate		**.22%**
During the period (August 1, 2015 – October 31, 2015):		
Average amount outstanding	$	**372,600**
Minimum amount outstanding		**290,000**
Maximum amount outstanding		**445,000**
Minimum interest rate		**.16%**
Maximum interest rate		**.25%**
Weighted average interest rate		**.22%**
Maximum amount outstanding during the month:		
August 2015	$	**430,000**
September 2015		**445,000**
October 2015		**380,000**
During the year ended October 31, 2015:		
Average amount outstanding	$	**361,100**
Minimum amount outstanding		**230,000**
Maximum amount outstanding		**580,000**
Minimum interest rate		**.15%**
Maximum interest rate		**.30%**
Weighted average interest rate		**.21%**

In thousands		2014
End of period (October 31, 2014):		
Amount outstanding	$	355,000
Weighted average interest rate		.17%
During the period (August 1, 2014 – October 31, 2014):		
Average amount outstanding	$	420,900
Minimum amount outstanding		275,000
Maximum amount outstanding		535,000
Minimum interest rate		.10%
Maximum interest rate		.25%
Weighted average interest rate		.17%
Maximum amount outstanding during the month:		
August 2014	$	525,000
September 2014		535,000
October 2014		355,000
During the year ended October 31, 2014:		
Average amount outstanding	$	441,500
Minimum amount outstanding		275,000
Maximum amount outstanding		625,000
Minimum interest rate		.10%
Maximum interest rate		.43%
Weighted average interest rate		.19%

As of October 31, 2015, we had $10 million available for letters of credit under our revolving syndicated credit facility, of which $1.6 million were issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. As of October 31, 2015, unused lines of credit available under our revolving syndicated credit facility, including the issuance of the letters of credit, totaled $508.4 million.

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. The major factors that affect our working capital are 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 debt to meet seasonal working capital needs. The level of short-term debt can vary significantly due to changes as discussed above. During our first and second quarters, we generally experience overall positive cash flows from the sale of flowing gas and gas withdrawal from storage and the collection of amounts billed to customers during the November through March winter heating season. Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases injected into storage, construction activity and decreases in receipts from customers.

During the winter heating season, our trade accounts payable increases 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 changes in the price of natural gas, which is a function of market fluctuations in the commodity cost 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 as amounts due to or 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. Regulatory margin stabilizing and cost recovery mechanisms, such as decoupled tariffs and those that allow us to recover the gas cost portion of bad debt expense, mitigate the impact that customer conservation and higher bad debt expense may have on our results of operations. 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.

Net cash provided by operating activities was $371.6 million in 2015, $430.6 million in 2014 and $313.2 million in 2013. Net cash provided by operating activities reflects a $6.8 million decrease in net income in 2015 compared with 2014 primarily due to higher operating costs, costs resulting from the Acquisition and utility interest charges, partially offset by increased margin. The effect of changes in working capital on net cash provided by operating activities is described below:

- Trade accounts receivable and unbilled utility revenues decreased $10.2 million in the current period primarily due to the decrease in amounts billed to customers reflecting lower gas costs. Volumes sold to weather-sensitive residential and commercial customers decreased .4 million dekatherms as compared with the same prior period primarily due to 2.7% warmer weather during the current period.
- Net amounts due to customers decreased $16.8 million in the current period primarily due to a $45.5 million one-time bill credit to North Carolina customers and lower hedging costs, partially offset by deferred gas cost collections and refunds through rates, margin decoupling and WNA.
- Gas in storage decreased $15.8 million in the current period primarily due to a decrease in the weighted average cost of gas purchased for injections, offset slightly by increased volumes of gas in storage.
- Prepaid gas costs decreased $10.2 million in the current period primarily due to a decrease in the weighted average cost of gas purchased for injections. Under some gas supply asset management contracts, prepaid gas costs incurred during the summer months represent purchases of gas that are not available for sale, and therefore not recorded in inventory, until the start of the winter heating season.
- Trade accounts payable increased $14.6 million in the current period primarily due to the timing of utility capital expenditures, partially offset by lower prices for natural gas purchases.

Primarily due to bonus depreciation, we generated federal NOLs in our tax years 2012, 2013 and 2014. We filed claims to carryback a portion of the NOLs to prior federal income tax returns. We recorded approximately $27 million in "Income taxes receivable" in "Current Assets" in the Consolidated Balance Sheets for refundable income taxes from the carryback of theses NOLs in 2014. We are currently under audit by the Internal Revenue Service for our 2012 tax year. Due to the timing of the audit, we reclassified $26 million of current refundable income taxes to "Income taxes receivable" in "Noncurrent Assets" in the Consolidated Balance Sheets from the carryback of these NOLs in 2015.

The Tax Increase Prevention Act of 2014 (the Act), enacted December 19, 2014, retroactively extended the 50% bonus depreciation that expired December 2013 for a year to December 2014. Under the Act, we were entitled to additional tax depreciation deductions for 2014. These additional deductions resulted in generating a federal NOL in 2014. We utilized tax NOL carryforwards to offset our taxable income in 2015. We anticipate that we will generate future taxable income sufficient to utilize tax carryforwards prior to the expiration of the carryforward period. For further information on tax carryforwards as of October 31, 2015, see Note 12 to the consolidated financial statements in this Form 10-K.

The Protecting Americans from Tax Hikes Act of 2015, enacted in December 2015, retroactively extends bonus depreciation that expired in December 2014. Under this legislation, qualified property placed in service during 2015 is eligible for 50% bonus depreciation. This retroactive extension of bonus depreciation will increase our federal NOLs as of October 31, 2015 by approximately $135 million.

Our three state regulatory commissions approve rates that are designed to give us the opportunity to generate revenues to cover our gas costs, fixed and variable non-gas costs and earn a fair return for our shareholders. We have WNA mechanisms in South Carolina and Tennessee that partially offset the impact of colder- or warmer-than-normal weather on bills rendered in November through March for residential and commercial customers in South Carolina and in October through April for residential and commercial customers in Tennessee. The WNA mechanisms in South Carolina and Tennessee generated credits to customers of $6.8 million and $8.4 million in 2015 and 2014, respectively, and charges of $3 million in 2013. In Tennessee, adjustments are made directly to individual customer monthly bills. In South Carolina, the adjustments are calculated at the individual customer level but are recorded in "Amounts due from customers" in "Regulatory Assets" or "Amounts due to customers" in "Regulatory Liabilities," as presented in Note 3 to the consolidated financial statements in this Form 10-K, 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 weather and consumption patterns. The margin decoupling mechanism reduced margin by $27 million and $33.4 million in 2015 and 2014, respectively, and increased margin by $6 million in 2013. Our gas costs are recoverable through purchased gas adjustment (PGA) procedures and are not affected by the WNA or the margin decoupling mechanisms.

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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.

We face competition from 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. Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment. Numerous factors can influence customer demand for natural gas, including price, value, availability, environmental attributes, comfort, convenience, 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 the relative prices of energy. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the U.S. dollar versus other currencies. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

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

Cash Flows from Investing Activities. Net cash used in investing activities was $478.4 million in 2015, $504.4 million in 2014 and $663.5 million in 2013. Net cash used in investing activities was primarily for utility capital expenditures. Gross utility capital expenditures were $443.7 million in 2015 as compared to $460.4 million in 2014 primarily due to lower spending on transmission integrity projects and the completion of early phases of the work and asset management system. Gross utility capital expenditures were $460.4 million in 2014 compared to $600 million in 2013 primarily due to lower power generation service delivery project expenditures and lower maintenance expenditures.

We have a substantial capital expansion program for construction of transmission and distribution facilities, purchase of equipment and other general improvements. Our program supports our system infrastructure, the growth in our customer base and large amounts for pipeline integrity, safety and compliance programs, including systems and technology infrastructure to enhance our pipeline system and integrity through a comprehensive work and asset management system. Significant utility construction expenditures are expected for growth and system integrity and are part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years. We are contractually obligated to expend capital as the work is completed.

Detail of our forecasted 2016 – 2018 utility capital expenditures, including AFUDC, and our commitments to fund equity method investments is presented below. We intend to fund capital expenditures in a manner that maintains our targeted capitalization ratio of 50 – 60% in total debt and 40 – 50% in common equity. A portion of the funding for capital expenditures is derived from operations, including lower federal income tax payments due to accelerated depreciation.

In millions	2016	2017	2018
Customer growth and other	$ 290	$ 310	$ 385
System integrity	270	255	210
Total forecasted utility capital expenditures	560	$ 565	595
Forecasted funding of construction in equity method investments	116	104	69

Total	$ 676	$ 669	$ 664

During fiscal 2013, we placed into service natural gas pipeline and compression facilities to provide natural gas delivery service to a Duke Energy Progress, Inc., (now a subsidiary of Duke Energy) power generation facility at their Sutton site near Wilmington, North Carolina. Our investment in the pipeline and compression facilities was supported by a long-term service agreement with fixed monthly payments.

Our Sutton project facilities created cost effective expansion capacity that we will also use to help serve the growing natural gas requirements of our customers in the eastern part of North Carolina. In 2015, a special contracts credit, representing the depreciation of investments under our power generation contracts, reduced the IMR revenue requirement under the IMR mechanism.

In June 2014, we executed an agreement to construct approximately 1.5 miles of natural gas transmission pipeline and associated compression to serve Duke Energy's W.S. Lee power generation facility near Anderson, South Carolina. Our total investment is estimated to be $38 million, with expenditures occurring primarily in our fiscal year 2016, and is included in the table above in the line "Customer growth and other." This agreement is supported by a long-term natural gas service agreement with fixed monthly charges and has a target in-service date of May 2017.

Also, in May 2015, we executed an agreement to construct a delivery station and associated compression to provide additional service to Duke Energy's power generation facility at their Sutton site as discussed above. Our total investment is estimated to be $13 million with expenditures occurring primarily in our fiscal years 2016 and 2017, and is included in the table above in the line "Customer growth and other." This agreement is supported by a long-term natural gas service agreement with fixed monthly charges and has a target in-service date of June 2017.

We are invested as equity members in two interstate natural gas pipeline projects that are in the process of development. As a member of these limited liability companies, we are committed to fund construction in proportion to our ownership interests. For further information regarding these investments, see Note 13 to the consolidated financial statements in this Form 10-K.

In millions	Constitution (24% ownership interest)	ACP (10% ownership interest)
Our anticipated contributions for total projects costs	$ 200.2	$ 450 - 500
Anticipated in-service date	fourth quarter of 2016	late 2018
Our contributions:		
For the year ended October 31, 2015	19.1	10.6
Over life of project to date	72.7	10.6

In connection with the ACP project, we plan to make additional utility capital investments in our natural gas delivery system, predominately in fiscal 2017 and 2018, of approximately $190 million in order to redeliver ACP gas supplies to local North Carolina markets we serve. Of that amount, approximately $170 million will be supported by third-party contracts. These expenditures are driving the increase in utility capital expenditures for fiscal 2018 for customer growth as shown above in the schedule of forecasted capital expenditures.

Cash Flows from Financing Activities. Net cash provided by financing activities was $110.9 million in 2015, $75.4 million in 2014 and $356.3 million in 2013. Funds are primarily provided from long-term debt securities, short-term borrowings and the issuance of common stock through our dividend reinvestment and stock purchase plan (DRIP) and our employee stock purchase plan (ESPP). We may sell common stock and issue long-term debt when market and other conditions favor such long-term financing to maintain our target capital structure of 40 – 50% equity to total capital. Funds are primarily used to finance capital expenditures, retire long-term debt maturities, pay down outstanding short-term debt, repurchase common stock under the common stock repurchase program when required to maintain target capital structure, pay quarterly dividends on our common stock and for other general corporate purposes.

Outstanding debt under our CP program decreased from $355 million as of October 31, 2014 to $340 million as of October 31, 2015 primarily due to net proceeds received from the issuance of long-term debt and our common stock. As discussed above in "Short-Term Debt" in "Financial Condition and Liquidity," we amended and extended our existing $850 million five-year revolving syndicated credit facility, including an option to request an expansion of financing commitments by an additional $200 million. For further information on short-term debt, see Note 6 to the consolidated financial statements in this Form 10-K.

In June 2014, we filed a combined debt and equity shelf registration statement with the SEC that became effective on June 6, 2014. The NCUC approved debt and equity issuances under this shelf registration up to $1 billion during its three-year life. Unless otherwise specified at the time such securities are offered for sale, the net proceeds from the sale of the securities will be used to finance capital expenditures, to repay outstanding short-term, unsecured notes under our CP program, to refinance other indebtedness, to repurchase our common stock, to pay dividends and for general corporate purposes. Pending such use, we may temporarily invest any net proceeds that are not applied to the purposes mentioned above in investment-grade securities.

Under this shelf registration statement, we established an ATM equity sales program, including a forward sales component. On January 7, 2015, we entered into separate ATM Equity Offering Sales Agreements (Sales Agreements) with Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, in their capacity as agents and/or principals (Agents). Under the terms of the Sales Agreements, we may issue and sell, through either of the Agents, shares of our common stock, up to an aggregate sales price of $170 million (subject to certain exceptions) during the period beginning January 2015 and ending October 31, 2016. Any such shares of our common stock would be offered and sold under our shelf registration statement and related prospectuses.

Our ability to sell our common stock up to the specified $170 million limit will depend on a variety of circumstances, including equity market conditions, trading volume in our common stock and other factors outside our control. We cannot predict the timing of any such sales or the aggregate amount of shares that may be sold under the ATM program. In addition, the ATM program allows us, at our option, to sell shares pursuant to FSAs with affiliates of our sales agents (forward counterparties) under the related ATM program sales agreements. Shares sold pursuant to FSAs settle on dates specified by us, which may be substantially after the sales occur but not later than October 31, 2016, subject to certain exceptions. As of October 31, 2015, all FSAs have been settled in shares, and we intend to settle any future FSAs in shares. Under the terms of the Merger Agreement, we would need to obtain Duke Energy's prior consent to cash or net settle a FSA.

The table below presents equity transactions under the open registration statements over the three-year period ended October 31, 2015.

				Per share		
Equity Issuance Transaction	Number of Shares	Settled	Net Proceeds Before Issuance Costs [(1)] (In thousands)	Public Offering Price	Net Settlement Price	Underwriting Discount
Underwriting agreement, January 2013:						
Issued	3,000,000	February 2013	$ 92,640	$ 32.00	$ 30.88	$ 1.12
FSAs physically settled in shares	1,600,000	December 2013	47,302		30.88	
	4,600,000		$ 139,942			
ATM program, physically settled in shares:						
FSA - executed March 2015	612,000	October 2015	$ 21,729		35.50 [(2)]	
FSA - executed June 2015	795,529	October 2015	28,230		35.49 [(2)]	
FSA - executed September 2015	114,500	October 2015	4,125		36.03 [(2)]	
Total ATM program	1,522,029		$ 54,084			

(1) Issuance costs incurred as follows: February 2013 shares - $370, December 2013 shares - $12, and October 2015 shares - $377.

(2) Net of 1.5% commission plus other adjustments.

We used the net proceeds from the equity transactions presented above to finance capital expenditures, repay outstanding notes under the unsecured CP program and for general corporate purposes. As of October 31, 2015, we have approximately $114.1 million remaining under the ATM program. For further information on our common stock and for more details on these equity issuance transactions, see Note 7 to the consolidated financial statements in this Form 10-K.

As of October 31, 2015, we have $544.1 million remaining under the shelf registration statement for debt and equity issuances as approved by the NCUC. We plan to issue equity capital in our fiscal year 2016, at such amounts to support our capital investment program and maintain our target capital structure of 50 – 60% in total debt and 40 – 50% in common equity. In addition to issuing common stock under our DRIP and ESPP as described above, we expect to continue to issue common stock under our ATM program as described above through the end of fiscal 2016.

We continually monitor customer growth trends and investment opportunities in our markets and the timing of any infrastructure investments that would require the need for additional long-term debt. The table below presents the activity of our long-term debt during the three-year period ended October 31, 2015. For further information on our long-term debt instruments, see Note 5 to the consolidated financial statements in this Form 10-K.

In millions	Issued (Redeemed)	Date Issued/Redeemed	Cash Impact
Senior Notes:			
4.65%, due August 1, 2043 (1)	$ 300	August 2013	$ 299.9 (3)
4.10%, due September 18, 2034 (2)	250	September 2014	249.6 (3)
3.60%, due August 15, 2025(2)	150	September 2015	149.9 (3)
Medium-Term Notes:			
5.00%, due December 19, 2013	(100)	December 2013	(100.0)

(1) The net proceeds were used to finance capital expenditures, to repay the balance of $100 million of our 5% Medium-Term Notes listed below, to repay outstanding short-term notes under our unsecured CP program and for general corporate purposes.

(2) The net proceeds were used to finance capital expenditures, to repay outstanding short-term unsecured notes under our CP program and for general corporate purposes.

(3) Net of debt discount.

From time to time, we have repurchased shares of common stock under our Common Stock Open Market Purchase Program as described in Note 7 to the consolidated financial statements in this Form 10-K. We did not repurchase any or our common stock under our Common Stock Open Market Purchase Program during the three-year period ended October 31, 2015, nor do we anticipate repurchasing our common stock in fiscal year 2016. During the effectiveness of the Merger Agreement, we are prohibited from repurchasing our common stock.

During 2015, we issued $27 million of common stock through DRIP and ESPP. During 2014 and 2013, we issued $25.6 million and $24.6 million, respectively, through these plans.

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 over the past three fiscal years. Dividends of $103.4 million, $99.2 million and $92.1 million in 2015, 2014 and 2013, respectively, were paid on common stock. Provisions contained in certain note agreements under which certain long-term debt was issued restrict the amount of cash dividends that may be paid. As of October 31, 2015, our ability to pay dividends was not restricted by these note agreements. On December 11, 2015, the Board of Directors declared a quarterly dividend on common stock of $.33 per share, payable January 15, 2016 to shareholders of record at the close of business on December 24, 2015. For further information on our long-term debt, see Note 5 to the consolidated financial statements in this Form 10-K.

Our targeted capitalization ratio is 50 – 60% in total debt and 40 – 50% in common equity. The components of our total debt outstanding (short-term and long-term, excluding unamortized discount and debt issuance costs) to our total capitalization as of October 31, 2015 and 2014 are summarized in the table below.

	October 31		October 31	
In thousands	**2015**	**Percentage**	2014	Percentage
Short-term debt	**$ 340,000**	**10%**	$ 355,000	12%
Current portion of long-term debt	**40,000**	**1%**	—	—%
Long-term debt, principal	**1,535,000**	**46%**	1,425,000	46%
Total debt	**1,915,000**	**57%**	1,780,000	58%
Common stockholders' equity	**1,426,312**	**43%**	1,308,602	42%
Total capitalization (including short-term debt)	**$ 3,341,312**	**100%**	$ 3,088,602	100%

Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. The borrowing costs under our revolving syndicated credit facility and our unsecured CP program are based on our credit ratings, and consequently, any decrease in our credit ratings would increase our borrowing costs. We believe our credit ratings will allow us to continue to have access to the capital markets, as and when needed, at a reasonable cost of funds.

	Qualified Pension	Nonqualified Pension	Other Benefits
Discount rates used to measure benefit costs in 2016:			
Service cost	4.46%	N/A	4.67%
Interest cost	3.25%	2.98%	3.51%
Discount rate that would have been used to measure service and interest costs under prior actuarial methodology	4.34%	3.85%	4.38%
Reduction in components of expected 2016 benefit costs using specific spot rates:		Impact in thousands	
Service cost	$ 153	N/A	$ 11
Interest cost	3,280	$ 45	320

The health care cost trend rate used in the prior actuarial calculations is not applicable under the 2016 methodology to measure either the benefit cost or the obligation for postretirement benefits. This is due to the new plan design where Piedmont's HRA contribution will be fixed as discussed above.

Gas Supply and Regulatory Proceedings

The source of our gas supply that we distribute to our customers is contracted from a diverse portfolio of major and independent producers and marketers and interstate and intrastate pipeline and storage operators. In late 2012, we entered into long-term contracts that would provide diversification in our supply portfolio to bring abundant and low cost natural gas supplies from the Marcellus supply basin to our natural gas markets in the Carolinas. The long-term contract with Cabot Oil & Gas (Cabot) to purchase firm, price-competitive Marcellus gas supplies and the long-term firm capacity contract with Williams – Transco under its Leidy Southeast expansion to transport the Cabot gas supplies to our markets began partial service in December 2015. Our long-term firm capacity contract with Williams – Transco under its Virginia Southside expansion allowing us to further diversify our supply portfolio with Marcellus based natural gas began service in September 2015. Also, in October 2014, we contracted for long-term pipeline capacity from diverse gas supply basins in central West Virginia under the ACP project that is proposed to be effective for the winter 2018 – 2019 season. We believe that these new natural gas supplies will provide diversification, reliability and gas cost benefits to Piedmont's customers across the Carolinas.

Natural gas demand is continuing to grow in our service area as discussed in the preceding section of "Cash Flows from Investing Activities" in this Form 10-K. For further information on our equity ventures, particularly ACP's future service to our expanding markets, see Note 13 to the consolidated financial statements in this Form 10-K.

As approved by our state regulatory commissions, secondary market transactions permit us to market gas supplies and transportation services by contract with wholesale or off-system customers. These sales normally contribute smaller per-unit margins to earnings; however, the programs allow us to act as a wholesale marketer of natural gas and transportation capacity when market conditions permit and when the supply and capacity are not required to serve our retail distribution system. For further information on secondary market transactions, see Note 3 to the consolidated financial statements in this Form 10-K.

We continue to work with our regulatory commissions to earn a fair rate of return on invested capital for our shareholders and provide safe, reliable natural gas distribution service to our customers. For further information about regulatory proceedings and other regulatory information, see Note 3 to the consolidated financial statements in this Form 10-K.

Equity Method Investments

For information about our equity method investments, see Note 13 to the consolidated financial statements in this Form 10-K.

Environmental Matters

We have developed an environmental self-assessment plan to examine 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 Manufactured Gas Plant 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 site remediation. For additional information on environmental matters, see Note 9 to the consolidated financial statements in this Form 10-K.

Accounting Guidance

For information on accounting guidance, see Note 1 to the consolidated financial statements in this Form 10-K.

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 all of these risks in accordance with defined policies and procedures under the direction of the Treasurer and Chief Risk Officer and our Enterprise Risk Management (ERM) program, including our Energy Price Risk Management Committee. Risk management is guided by senior management with Board of Directors oversight, and senior management takes an active role in the development of policies and procedures.

In fiscal 2014, the Board of Directors delegated oversight of our ERM program to the Finance and Enterprise Risk (FER) Committee. All other committees of our Board of Directors have enhanced monitoring of those risks relating to areas over which they have oversight responsibility. The Board of Directors approved risk tolerances for several major areas of risk exposure, namely strategic, commercial, market, financial, operational, regulatory and reputational risks, and receives quarterly reports from the FER Committee and annual reports from management.

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, or in situations where counterparties do not have investment-grade or functionally equivalent credit ratings, our policy requires credit enhancements that include letters of credit or parental guaranties. In either circumstance, the policy specifies limits on the contract amount and duration based on the counterparty's credit rating and/or credit support. In order to minimize our exposure, we continually re-evaluate third-party creditworthiness and market conditions and modify our requirements accordingly.

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

We have mitigated our exposure to the risk of non-payment of utility bills by our customers. In all three states, gas costs related to uncollectible accounts are 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 our high risk customers that do not satisfy our predetermined credit standards until a satisfactory payment history has been established. Significant increases in the price of natural gas or colder-than-normal weather can 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, 2015, 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, 2015, we had $340 million of short-term debt outstanding as commercial paper at an interest rate of .22%. The carrying amount of our short-term debt approximates fair value. A change of 100 basis points in the underlying average interest rate for our short-term debt would have caused a change in interest expense of approximately $3.6 million during 2015.

As of October 31, 2015, information about our long-term debt is presented below.

In millions	Expected Maturity Date							Fair Value as of October 31, 2015
	2016	2017	2018	2019	2020	Thereafter	Total	
Fixed Rate Long-term Debt	$ 40	$ 35	$ —	$ —	$ —	$ 1,500	$ 1,575	$ 1,720.6
Average Interest Rate	2.92%	8.51%	—%	—%	—%	4.75%	4.79%	

Commodity Price Risk

We have mitigated the cash flow risk resulting from commodity purchase contracts under our regulatory gas cost recovery mechanisms that permit the recovery of these costs in a timely manner. However, we face regulatory recovery risk associated with these costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas, including costs associated with our hedging programs under the recovery mechanism allowed by each of our state regulators. Under our PGA procedures, differences between gas costs incurred and gas costs billed to customers are deferred and any under-recoveries are included in “Amounts due from customers” in “Regulatory Assets” or any over-recoveries are included in “Amounts due to customers” in “Regulatory Liabilities” as presented in Note 3 to the consolidated financial statements in this Form 10-K, for collection or refund over subsequent periods. When we have “Amounts due from customers,” we earn a carrying charge that mitigates any incremental short-term borrowing costs. When we have “Amounts due to customers,” we incur a carrying charge that we must refund to our customers.

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

We purchase firm gas from a diverse portfolio of suppliers at liquid exchange points. For term suppliers whose performance is greater than one month, we evaluate and monitor their creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds, in case a supplier defaults. Since substantially all of our commodity supply contracts are at market index prices tied to liquid exchange points and with our significant storage flexibility, we believe that it is unlikely that a supplier default would have a material effect on our financial position, results of operations or cash flows.

Our gas purchasing practices are subject to regulatory reviews in all three states in which we operate. We are responsible for following competitive and reasonable practices in purchasing gas for our customers. Costs have never been disallowed on the basis of prudence in any jurisdiction.

Weather Risk

We are exposed to weather risk in our regulated utility segment in South Carolina and Tennessee where revenues are collected from volumetric rates without a margin decoupling mechanism. Our rates are designed based on an assumption of normal weather. This risk is mitigated by a WNA mechanism designed to offset the impact of colder-than-normal or warmer-than-normal weather in our residential and commercial markets during the months of November through March in South Carolina and October through April in Tennessee. The WNA formulas do not ensure full recovery of approved margin during periods when customer consumption patterns vary from those used to establish the WNA factors. In North Carolina, we manage our weather risk through a year round margin decoupling mechanism that allows us to recover our approved margin from residential and commercial customers independent of volumes sold. We are exposed to weather risks in our industrial markets to the extent our margin is collected through volumetric rates in all of our jurisdictions.

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

Item 8. Financial Statements and Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2015 and 2014, and the related consolidated statements of comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2015, 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, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 23, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 23, 2015

Consolidated Balance Sheets
October 31, 2015 and 2014

ASSETS

In thousands	2015	2014
Utility Plant:		
Utility plant in service	$ **5,426,584**	$ 5,011,497
Less accumulated depreciation	**1,251,940**	1,166,922
Utility plant in service, net	**4,174,644**	3,844,575
Construction work in progress	**170,250**	141,693
Plant held for future use	**3,155**	3,155
Total utility plant, net	**4,348,049**	3,989,423
Other Physical Property, at cost (net of accumulated depreciation of $926 in 2015 and $904 in 2014)	**332**	355
Current Assets:		
Cash and cash equivalents	**13,744**	9,643
Trade accounts receivable [(1)] (less allowance for doubtful accounts of $1,648 in 2015 and $2,152 in 2014)	**59,248**	65,260
Income taxes receivable	**11,447**	36,100
Other receivables	**10,667**	3,361
Unbilled utility revenues	**17,422**	21,093
Inventories:		
Gas in storage	**68,240**	84,081
Materials, supplies and merchandise	**1,251**	1,652
Gas purchase derivative assets, at fair value	**1,343**	4,898
Regulatory assets	**10,936**	27,837
Prepayments	**28,903**	39,030
Deferred income taxes	**32,392**	53,418
Other current assets	**344**	326
Total current assets	**255,937**	346,699
Noncurrent Assets:		
Equity method investments in non-utility activities	**206,956**	170,171
Goodwill	**48,852**	48,852
Regulatory assets	**196,726**	174,281
Income taxes receivable	**26,023**	—
Marketable securities, at fair value	**4,666**	3,727
Overfunded postretirement asset	**17,770**	33,757
Other noncurrent assets	**5,439**	7,042
Total noncurrent assets	**506,432**	437,830
Total	$ **5,110,750**	$ 4,774,307

(1) See Note 13 for amounts attributable to affiliates.

See notes to consolidated financial statements.

Consolidated Balance Sheets
October 31, 2015 and 2014

CAPITALIZATION AND LIABILITIES

In thousands	2015	2014
Capitalization:		
Stockholders' equity:		
Cumulative preferred stock - no par value - 175 shares authorized	$ —	$ —
Common stock – no par value – shares authorized: 200,000; shares outstanding: 80,883 in 2015 and 78,531 in 2014	**721,419**	636,835
Retained earnings	**705,748**	672,004
Accumulated other comprehensive loss	**(855)**	(237)
Total stockholders' equity	**1,426,312**	1,308,602
Long-term debt, net	**1,523,677**	1,414,484
Total capitalization	**2,949,989**	2,723,086
Current Liabilities:		
Current maturities of long-term debt	**40,000**	—
Short-term debt	**340,000**	355,000
Trade accounts payable [1]	**99,895**	85,299
Other accounts payable	**52,149**	54,349
Accrued interest	**29,488**	27,982
Customers' deposits	**20,896**	19,994
General taxes accrued	**27,940**	23,828
Regulatory liabilities	**13,367**	46,231
Other current liabilities	**11,861**	9,303
Total current liabilities	**635,596**	621,986
Noncurrent Liabilities:		
Deferred income taxes	**861,615**	809,467
Unamortized federal investment tax credits	**1,027**	1,193
Accumulated provision for postretirement benefits	**14,975**	15,471
Regulatory liabilities	**590,301**	558,598
Conditional cost of removal obligations	**19,712**	14,647
Other noncurrent liabilities	**37,535**	29,859
Total noncurrent liabilities	**1,525,165**	1,429,235
Commitments and Contingencies (Note 9)		
Total	**$ 5,110,750**	$ 4,774,307

[1] See Note 13 for amounts attributable to affiliates.

See notes to consolidated financial statements.

Consolidated Statements of Comprehensive Income
For the Years Ended October 31, 2015, 2014 and 2013

In thousands, except per share amounts	2015	2014	2013
Operating Revenues (1)	$ 1,371,718	$ 1,469,988	$ 1,278,229
Cost of Gas (1)	644,424	779,780	656,739
Margin	727,294	690,208	621,490
Operating Expenses:			
Operations and maintenance	294,517	270,877	253,120
Depreciation	128,704	118,996	112,207
General taxes	42,110	37,294	34,635
Utility income taxes	76,934	83,176	77,334
Total operating expenses	542,265	510,343	477,296
Operating Income	185,029	179,865	144,194
Other Income (Expense):			
Income from equity method investments	34,461	32,753	26,056
Non-operating income	3,164	1,842	2,839
Non-operating expense	(3,724)	(4,331)	(5,122)
Income taxes	(13,288)	(11,642)	(8,612)
Total other income (expense)	20,613	18,622	15,161
Utility Interest Charges:			
Interest on long-term debt	70,619	61,562	54,158
Allowance for borrowed funds used during construction	(11,106)	(16,427)	(30,975)
Other	9,118	9,551	1,755
Total utility interest charges	68,631	54,686	24,938
Net Income	137,011	143,801	134,417
Other Comprehensive Income (Loss), net of tax:			
Unrealized gain (loss) from hedging activities of equity method investments, net of tax of ($1,028), $225 and ($69) for the years ended October 31, 2015, 2014 and 2013, respectively	(1,601)	355	(109)
Reclassification adjustment of realized (gain) loss from hedging activities of equity method investments included in net income, net of tax of $652, ($177) and $85 for the years ended October 31, 2015, 2014 and 2013, respectively	1,018	(284)	130
Net current period benefit activities of equity method investments, net of tax of ($23) and ($16) for the years ended October 31, 2015 and 2014, respectively	(35)	(24)	
Total other comprehensive income (loss)	(618)	47	21
Comprehensive Income	$ 136,393	$ 143,848	$ 134,438
Average Shares of Common Stock:			
Basic	78,942	77,883	74,884
Diluted	79,231	78,193	75,333
Earnings Per Share of Common Stock:			

Basic	**$**	**1.74**	$	1.85	$	1.80
Diluted	**$**	**1.73**	$	1.84	$	1.78

(1) See Note 13 for amounts attributable to affiliates.

See notes to consolidated financial statements.

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2015, 2014 and 2013

In thousands	2015	2014	2013
Cash Flows from Operating Activities:			
Net income	$ **137,011**	$ 143,801	$ 134,417
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**140,217**	129,343	120,797
Provision for doubtful accounts	**5,095**	6,959	5,314
Impairment loss on investment	—	2,000	—
Net gain on sale of property	—	(817)	(349)
Income from equity method investments	**(34,461)**	(32,753)	(26,056)
Distributions of earnings from equity method investments	**24,875**	24,843	22,139
Deferred income taxes, net	**73,407**	87,136	57,637
Changes in assets and liabilities:			
Gas purchase derivatives, at fair value	**3,555**	(3,064)	1,319
Receivables, net	**(2,637)**	9,785	(28,616)
Inventories	**16,242**	(10,079)	(2,059)
Settlement of legal asset retirement obligations	**(5,563)**	(3,575)	(2,389)
Regulatory assets	**(14,917)**	20,297	43,338
Other assets	**16,220**	(2,829)	4,629
Accounts payable	**(7,626)**	18	2,381
Contributions to benefit plans	**(12,728)**	(22,516)	(22,415)
Accrued/deferred postretirement benefit costs	**28,219**	20,446	(31,100)
Regulatory liabilities	**(16,065)**	49,468	23,429
Other liabilities	**20,791**	12,149	10,831
Net cash provided by operating activities	**371,635**	430,612	313,247
Cash Flows from Investing Activities:			
Utility capital expenditures	**(443,654)**	(460,444)	(599,999)
Allowance for borrowed funds used during construction	**(11,106)**	(16,427)	(30,975)
Contributions to equity method investments	**(29,723)**	(37,642)	(41,348)
Distributions of capital from equity method investments	**1,505**	3,929	4,700
Proceeds from sale of property	**717**	1,883	1,951
Investments in marketable securities	**(866)**	(454)	(414)
Other	**4,707**	4,708	2,609
Net cash used in investing activities	**(478,420)**	(504,447)	(663,476)

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2015, 2014 and 2013

In thousands	2015	2014	2013
Cash Flows from Financing Activities:			
Borrowings under credit facility	**$ —**	$ —	$ 10,000
Repayments under credit facility	**—**	—	(10,000)
Net (repayments) borrowings - commercial paper	**(15,000)**	(45,000)	35,000
Proceeds from issuance of long-term debt, net of discount	**149,902**	249,565	299,856
Repayment of long-term debt	**—**	(100,000)	—
Expenses related to issuance of debt	**(1,330)**	(2,871)	(3,250)
Proceeds from issuance of common stock, net of expenses	**53,707**	47,290	92,271
Issuance of common stock through dividend reinvestment and employee stock plans	**26,992**	25,556	24,610
Dividends paid	**(103,390)**	(99,151)	(92,146)
Other	**5**	26	(8)
Net cash provided by financing activities	**110,886**	75,415	356,333
Net Increase in Cash and Cash Equivalents	**4,101**	1,580	6,104
Cash and Cash Equivalents at Beginning of Year	**9,643**	8,063	1,959
Cash and Cash Equivalents at End of Year	**$ 13,744**	$ 9,643	$ 8,063
Cash Paid During the Year for:			
Interest	**$ 71,519**	$ 64,276	$ 50,275
Income Taxes:			
Income taxes paid	**$ 3,680**	$ 10,840	$ 5,760
Income taxes refunded	**530**	30	169
Income taxes, net	**$ 3,150**	$ 10,810	$ 5,591
Noncash Investing and Financing Activities:			
Accrued construction expenditures	**$ 58,868**	$ 38,869	$ 39,389

See notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity
For the Years Ended October 31, 2015, 2014 and 2013

In thousands, except per share amounts	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, October 31, 2012	$ 442,461	$ 584,848	$ (305)	$ 1,027,004
Comprehensive Income:				
Net income		134,417		134,417
Other comprehensive income			21	21
Total comprehensive income				134,438
Common Stock Issued	119,552			119,552
Expenses from Issuance of Common Stock	(369)			(369)
Tax Benefit from Dividends Paid on ESOP Shares		117		117
Dividends Declared ($1.23 per share)		(92,146)		(92,146)
Balance, October 31, 2013	561,644	627,236	(284)	1,188,596
Comprehensive Income:				
Net income		143,801		143,801
Other comprehensive income			47	47
Total comprehensive income				143,848
Common Stock Issued	75,203			75,203
Expenses from Issuance of Common Stock	(12)			(12)
Tax Benefit from Dividends Paid on ESOP Shares		118		118
Dividends Declared ($1.27 per share)		(99,151)		(99,151)
Balance, October 31, 2014	636,835	672,004	(237)	1,308,602
Comprehensive Income:				
Net income		**137,011**		**137,011**
Other comprehensive loss			**(618)**	**(618)**
Total comprehensive income				**136,393**
Common Stock Issued	**84,966**			**84,966**
Expenses from Issuance of Common Stock	**(382)**			**(382)**
Tax Benefit from Dividends Paid on ESOP Shares		**123**		**123**
Dividends Declared ($1.31 per share)		**(103,390)**		**(103,390)**
Balance, October 31, 2015	**$ 721,419**	**$ 705,748**	**$ (855)**	**$ 1,426,312**

See notes to consolidated financial statements.

The components of accumulated other comprehensive income (loss) (OCIL) as of October 31, 2015 and 2014 are as follows.

In thousands	**2015**	2014

Hedging activities of equity method investments	**$ (796)**	$ (213)
Benefit activities of equity method investments	**(59)**	(24)

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Nature of Operations and Basis of Consolidation

Piedmont Natural Gas Company, Inc. 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, regulated interstate natural gas transportation and storage and regulated intrastate natural gas transportation. Our utility operations are regulated by three state regulatory commissions. Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Piedmont" means consolidated Piedmont Natural Gas Company, Inc. and its subsidiaries. For further information on regulatory matters, see Note 3 to the consolidated financial statements.

The consolidated financial statements of Piedmont have been prepared in conformity with generally accepted accounting principles in the United States of America (GAAP) and under the rules of the Securities and Exchange Commission (SEC). The consolidated financial statements reflect the accounts of Piedmont and its wholly-owned subsidiaries whose financial statements are prepared for the same reporting period as Piedmont using consistent accounting policies. Inter-company transactions have been eliminated in consolidation where appropriate; however, we have not eliminated inter-company profit on sales to affiliates and costs from affiliates in accordance with accounting regulations prescribed under rate-based regulation.

Investments in non-utility activities, or joint ventures, 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 "Noncurrent Assets" in the Consolidated Balance Sheets at cost plus post-acquisition contributions and earnings based on our share in each of the joint ventures less any distributions received from the joint venture, and if applicable, less any impairment in value of the investment. Earnings or losses from equity method investments are recorded in "Income from equity method investments" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. Revenues and expenses of all other non-utility activities are included in "Non-operating income" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. For further information on equity method investments and related party transactions, see Note 13 to the consolidated financial statements.

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated. There are no subsequent events that had a material impact on our financial position, results of operations or cash flows. For further information, see Note 16 to the consolidated financial statements.

On October 24, 2015, we entered into an Agreement and Plan of Merger (Merger Agreement) with Duke Energy Corporation (Duke Energy). For further information, see Note 2 to the consolidated financial statements.

Use of Estimates

In accordance with GAAP, we make certain estimates and assumptions regarding reported amounts of assets, liabilities, revenues and expenses and the related disclosures, using historical experience and other assumptions that we believe are reasonable at the time. Our estimates may involve complex situations requiring a high degree of judgment in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. These estimates and assumptions affect the reported amounts of 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 these estimates and assumptions, which are evaluated on a continual basis.

Segment Reporting

Our segments are based on the components of the Company for which we produce separate financial information internally that is used regularly by the chief operating decision maker (CODM) in deciding how to allocate resources and in assessing performance. Our CODM is the executive management team comprised of senior level management. Our segments are identified based on products and services, regulatory environments and our current corporate organization and business decision-making activities. We evaluate the performance of the regulated utility segment based on margin, operations and maintenance (O&M) expenses and operating income. We evaluate the performance of the regulated non-utility activities segment and the unregulated non-utility activities segment based on earnings from our cash flows in the ventures.

We have three reportable business segments, regulated utility, regulated non-utility activities and unregulated non-utility activities. The regulated utility segment is the gas distribution business, where we include the operations of merchandising and its related service work and home service agreements, with activities conducted by the utility. Although the operations of our regulated utility segment are located in three states under the jurisdiction of individual state regulatory commissions, the operations are managed as one unit having similar economic and risk characteristics. Operations of our regulated non-utility activities segment are comprised of our equity method investments in joint ventures with regulated activities that are held by our wholly-owned subsidiaries. Operations of our unregulated non-utility activities segment are comprised primarily of our equity method investment in a joint venture with unregulated activities that is held by a wholly-owned subsidiary; activities of our other minor subsidiaries are also included.

Operations of the regulated utility segment are reflected in "Operating Income" in the Consolidated Statements of Comprehensive Income. Earnings or losses from equity method investments of the regulated and unregulated non-utility activities segments are included in "Income from equity method investments" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. All other revenues and expenses of the regulated and unregulated non-utility activities segments are included in "Non-operating income" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. See Note 15 to the consolidated financial statements for further discussion of segments.

Rate-Regulated Basis of Accounting

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

Our regulatory assets are recoverable through either base rates or rate riders 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 commissions during any future rate proceedings. In the event that accounting for the effects of regulation were no longer applicable, we would recognize a write-off of the regulatory assets and regulatory liabilities that would result in an adjustment to net income or accumulated other comprehensive income (OCI). Our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate. It is our opinion that all regulatory assets are recoverable in current rates or in future rate proceedings.

Utility Plant and Depreciation

Utility plant is stated at original cost, including direct labor and materials, contractor costs, allocable overhead charges, such as engineering, supervision, corporate office salaries and expenses, pensions and insurance, and an allowance for funds used during construction (AFUDC) that is calculated under a formula prescribed by our state regulators. We apply the group method of accounting, where the costs of homogeneous assets are aggregated and depreciated by applying a rate based on the average expected useful life of the assets. Major expenditures that last longer than a year and improve or lengthen the expected useful life of the overall property from original expectations that are recoverable in regulatory rate base are capitalized while expenditures not meeting these criteria are expensed as incurred. The costs of property retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. On certain assets, like land, that are nondepreciable, we record a gain or loss upon the disposal of the property that is recorded in "Non-operating income" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income.

The classification of total utility plant, net, for the years ended October 31, 2015 and 2014 is presented below.

In thousands	2015	2014
Intangible plant	$ 3,374	$ 3,374
Other storage plant	180,960	180,058
Transmission plant	2,024,264	1,787,990
Distribution plant	2,766,871	2,623,560
General plant	452,301	421,763
Asset retirement cost	4,159	11
Contributions in aid of construction	(5,345)	(5,259)
Total utility plant in service	5,426,584	5,011,497
Less accumulated depreciation	(1,251,940)	(1,166,922)
Total utility plant in service, net	4,174,644	3,844,575
Construction work in progress	170,250	141,693
Plant held for future use	3,155	3,155
Total utility plant, net	$ 4,348,049	$ 3,989,423

Contributions in aid of construction represent nonrefundable donations or contributions received from third-parties for partial or full reimbursement for construction expenditures for utility plant in service.

AFUDC represents the estimated costs of funds from both debt and equity sources used to finance the construction of major projects and is capitalized for ratemaking purposes when the completed projects are placed in service. The portion of AFUDC attributable to borrowed funds is shown as a reduction of "Utility Interest Charges" in the Consolidated Statements of Comprehensive Income. Any portion of AFUDC attributable to equity funds would be included in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income. For the three years ended October 31, 2015, 2014 and 2013, all of our AFUDC was attributable to borrowed funds.

AFUDC for the years ended October 31, 2015, 2014 and 2013 is presented below.

In thousands	2015	2014	2013
AFUDC	$ 11,106	$ 16,427	$ 30,975

In accordance with utility accounting practice, we classified real estate and development costs associated with a liquefied natural gas (LNG) peak storage facility in the eastern part of North Carolina as "Plant held for future use" in the Consolidated Balance Sheets, due to construction being suspended in March 2009. As of 2012, approximately $3.2 million of the "Plant held for future use" related to land costs and approximately $3.5 million related to non-real estate costs. In May 2013, we filed a general rate application with the North Carolina Utilities Commission (NCUC) requesting rate recovery of the non-real estate costs. Under the settlement of the 2013 North Carolina general rate proceeding approved by the NCUC in December 2013, we agreed to the amortization and collection of $1.2 million of non-real estate costs that is recorded as a regulatory asset with amortization over 38 months beginning January 1, 2014 through February 2017. Under the settlement of our June 2014 rate stabilization adjustment (RSA) filing with the Public Service Commission of South Carolina (PSCSC) that was approved in October 2014, we agreed to the amortization and collection of $.5 million of non-real estate costs that was recorded as a regulatory asset with amortization over the 12 months beginning November 1, 2014. We recorded cumulative amortization of $1.8 million of non-real estate costs in fiscal year 2013 that is included in the Consolidated Statements of Comprehensive Income in "Other Income (Expense)" in "Non-operating expense." For further information on the 2013 general rate proceeding settlement of these costs for North Carolina or the 2014 RSA filing for South Carolina, see Note 3 to the consolidated financial statements.

We compute depreciation expense using the straight-line method over periods ranging from 5 to 80 years. The composite weighted-average depreciation rates were 2.48% for 2015, 2.54% for 2014 and 2.77% for 2013.

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 file the results with the regulatory commission. No such five-year requirement exists in South Carolina or Tennessee; however, we periodically propose revised rates in those states based on depreciation studies. Our last system-wide depreciation study based on fiscal year 2009 data was completed in 2011 and filed with the appropriate regulatory commission in all jurisdictions. New depreciation rates were approved effective November 1, 2011 for South Carolina, March 1, 2012 for Tennessee and January 1, 2014 for North Carolina.

As authorized by our regulatory commissions, the estimated costs of removal on certain regulated properties are collected through depreciation expense through rates 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 collect and record estimated non-legal costs of removal on any depreciable asset that includes cost of removal in its depreciation rate. Because the estimated removal costs are a non-legal obligation, we account for them as a regulatory liability and present the accumulated removal costs in "Regulatory Liabilities" in "Rate-Regulated Basis of Accounting" in Note 3 to the consolidated financial statements. For further discussion of this regulatory liability, see "Asset Retirement Obligations" in this Note 1.

Cash and Cash Equivalents

We consider instruments purchased with an original maturity at date of purchase of three months or less to be cash equivalents, particularly affecting the Consolidated Statements of Cash Flows. We have no restrictions on our cash balances that would impact the payment of dividends as of October 31, 2015 and 2014.

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 bill customers monthly with payment due within 30 days. 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. We write off our customers' accounts when they are deemed to be uncollectible. Pursuant to orders issued by the NCUC, the PSCSC and the Tennessee Regulatory Authority (TRA), we are authorized to recover actual uncollected gas costs through the purchased gas adjustment (PGA). As a result, only the portion of accounts written off relating to the non-gas costs, or margin, is included in base rates and, accordingly, only this portion is included in the provision for uncollectibles expense. Non-regulated merchandise and service work receivables due beyond one year are included in "Other noncurrent assets" in "Noncurrent Assets" in the Consolidated Balance Sheets.

We believe that we have provided an adequate allowance for any receivables which may not be ultimately collected. As of October 31, 2015 and 2014, our trade accounts receivable consisted of the following.

In thousands	**2015**	2014
Gas receivables	**$ 57,759**	$ 64,400
Non-regulated merchandise and service work receivables	**3,137**	3,012
Allowance for doubtful accounts	**(1,648)**	(2,152)
Trade accounts receivable	**$ 59,248**	$ 65,260

A reconciliation of the changes in the allowance for doubtful accounts for the years ended October 31, 2015, 2014 and 2013 is presented below.

In thousands	**2015**	2014	2013
Balance at beginning of year	**$ 2,152**	$ 1,604	$ 1,579
Additions charged to uncollectibles expense	**5,095**	6,959	5,314
Accounts written off, net of recoveries	**(5,599)**	(6,411)	(5,289)
Balance at end of year	**$ 1,648**	$ 2,152	$ 1,604

For information on credit risk, see "Credit and Counterparty Risk" in Note 8 of the consolidated financial statements.

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 enter into service contracts, or asset management arrangements (AMAs), with counterparties to efficiently manage portions of our gas supply, transportation capacity and storage capacity to serve our customers. These AMAs are structured in compliance with Federal Energy Regulatory Commission (FERC) Order 712. Generally, under an AMA, we receive a fixed monthly payment which is set at inception of the arrangement, and in return, we may assign the gas supply and/or storage inventory and release the transportation capacity and storage capacity to the asset manager for the term of the agreement. The inventory is assigned at no cost, and the same quantities are required to be returned at the expiration of the agreements. One agreement allows us to call on inventory during the summer months to satisfy operational requirements, if needed. The inventory that is assigned to the asset manager is available for our use during the winter heating season, November through March. We account for these amounts on the Consolidated Balance Sheets as a current asset in the inventories section as "Gas in storage." From the period of April through October, the inventory that is not available for our use is reclassified on the Consolidated Balance Sheets as a current asset in "Prepayments," and the inventory that is available for our use remains in "Gas in storage."

At October 31, 2015 and 2014, such counterparties held natural gas storage assets as recorded in "Prepayments," with a value of $24.8 million and $35 million, respectively, through such asset management relationships. Under the terms of the agreements, we receive asset management fees, which are recorded as secondary market transactions and shared between our utility customers and our shareholders. The AMAs expire at various times through March 31, 2017. For further information on the revenue sharing of secondary market transactions, see Note 3 to the consolidated financial statements.

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

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value in the Consolidated Balance Sheets are cash and cash equivalents, marketable securities held in rabbi trusts established for our deferred compensation plans and derivative assets and liabilities, if any, that are held for our utility operations. The carrying values of receivables, short-term debt, accounts payable, accrued interest and other current assets and liabilities approximate fair value as all amounts reported are to be collected or paid within one year. Our nonfinancial assets and liabilities include our qualified pension and postretirement plan assets and liabilities that are recorded at fair value in the Consolidated Balance Sheets in accordance with employers' accounting and related disclosures of postretirement plans.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit date. We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The fair value of our financial assets and liabilities are subject to potentially significant volatility based on changes in market prices, the portfolio valuation of our contracts, as well as the maturity and settlement of those contracts, and subsequent newly originated transactions, each of which directly affects the estimated fair value of our financial instruments. We are able to classify fair value balances based on the observance of those inputs at the lowest level that is significant to the fair value measurement, in its entirety, in the following fair value hierarchy levels as set forth in the fair value guidance.

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets have sufficient frequency and volume to provide pricing information for the asset or liability on an ongoing basis. Our Level 1 items consist of financial instruments of exchange-traded derivatives, investments in marketable securities and benefit plan assets held in registered investment companies and individual stocks.

Level 2 inputs are inputs other than quoted prices in active markets included in Level 1 and are either directly or indirectly corroborated or observable as of the reporting date, generally using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the marketplace. Our Level 2 items include non-exchange-traded derivative instruments, such as some qualified pension plan assets held in common trust funds, collateralized mortgage obligations, swaps, futures, currency forwards, corporate bonds and government and agency obligations that are valued at the closing price reported in the active market for similar assets in which the individual securities are traded or based on yields currently available on comparable securities of issuers with similar credit ratings or based on the most recent available financial information for the respective funds and securities. For some qualified pension plan assets, the determination of Level 2 assets was completed through a process of reviewing each individual security while consulting research and other metrics provided by investment managers, including a pricing matrix detailing the pricing source and security type, annual audited financial statements and a review of valuation policies and procedures used by the investment managers as well as our investment advisor.

Level 3 inputs include significant pricing inputs that are generally less observable from objective sources and may be used with internally developed methodologies that result in management's best estimate of fair value. Our Level 3 inputs include cost estimates for removal (contract fees or manpower/equipment estimates), inflation factors, risk premiums, the remaining life of long-lived assets, the credit adjusted risk free rate to discount for the time value of money over an appropriate time span, and the most recent available financial information of an investment in a diversified private equity fund of funds for some of our qualified pension plan assets. We do not have any other assets or liabilities classified as Level 3.

In determining whether to categorize the fair value measurement of an instrument as Level 2 or Level 3, we must use judgment to assess whether we have the ability as of the measurement date to redeem an investment at its net asset value per share (NAV) in the near term. We consider when we might have the ability to redeem the investment by reviewing contractual restrictions in effect as of the investment date as well as any potential restrictions that the investee may impose. Regarding our benefit plans' investments, "near term" is the ability to redeem an investment in no more than 180 days.

Transfers between different levels of the fair value hierarchy may occur based on the level of observable inputs used to value the instruments for the period. These transfers represent existing assets or liabilities previously categorized as Level 1 or Level 2 for which the inputs to the estimate became less observable or assets and liabilities previously classified as Level 2 or Level 3 for which the lowest significant input became more observable during the period. Transfers into and out of each level are measured at the actual date of the event or change in circumstances causing the transfer.

For the fair value measurements of our derivatives and marketable securities, see Note 8 to the consolidated financial statements. For the fair value measurements of our benefit plan assets, see Note 10 to the consolidated financial statements.

Goodwill, Equity Method Investments and Long-Lived Assets

Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. We annually evaluate goodwill for impairment as of October 31, or more frequently if impairment indicators arise during the year. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. When we test goodwill, we use a fair value approach at a reporting unit level, generally equivalent to our operating segments as discussed in Note 15 to the consolidated financial statements. An impairment charge would be recognized if the carrying value of the reporting unit, including goodwill, exceeded its fair value. All of our goodwill is attributable to the regulated utility segment.

Our annual goodwill impairment assessment as of October 31, 2015 was performed using a qualitative approach. As part of our qualitative assessment, we considered macroeconomic conditions such as general deterioration in economic condition, limitations on accessing capital and other developments in equity and credit markets. We evaluated industry and market considerations for any deterioration in the environment in which we operate, the increased competitive environment, a decline (both absolute and relative to our peers) in market-dependent multiples or metrics, any changes in the market for our products or services, and regulatory and political development. We assessed our overall financial performance and considered cost factors, such as increases in utility construction expenditures, labor or other costs, that would have a negative effect on earnings. We determined the relevance of any entity-specific events or events affecting our regulated utility segment which would have a negative effect on the carrying value of the reporting unit.

Based on our qualitative assessment, we have determined that it is not necessary to perform a quantitative goodwill impairment test as of October 31, 2015. The annual goodwill impairment assessments performed have indicated that it is more likely than not that the fair value of the reporting unit is substantially in excess of carrying value and not at risk of failing step one of the quantitative goodwill impairment test. No impairment was recognized during the years ended October 31, 2015, 2014 and 2013. The fair value of our regulated utility reporting unit substantially exceeds the carrying value, including goodwill.

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. In April 2014, we recorded a $2 million write-off for an investment that was accounted for on the cost basis. The write-off was recorded to "Non-operating expense" in the Consolidated Statements of Comprehensive Income. There were no events or circumstances during the years ended October 31, 2015 and 2013 that resulted in any impairment charges. For further information on equity method investments, see Note 13 to the consolidated financial statements.

Marketable Securities

We have marketable securities that are invested in money market and mutual funds that are liquid and actively traded on the exchanges. These securities are assets that are held in rabbi trusts established for our deferred compensation plans. For further information on the deferred compensation plans, see Note 10 to the consolidated financial statements.

We have classified these marketable securities as trading securities since their inception as the assets are held in rabbi trusts. Trading securities are recorded at fair value on the Consolidated Balance Sheets with any gains or losses recognized currently in earnings. We do not intend to engage in active trading of the securities, and participants in the deferred compensation plans may redirect their deemed investments at any time. We have matched the current portion of the deferred compensation liability with the current asset and noncurrent deferred compensation liability with the noncurrent asset; the current portion is included in “Other current assets” in “Current Assets” in the Consolidated Balance Sheets.

The money market investments in the trusts approximate fair value due to the short period of time to maturity. The fair values of the equity securities are based on quoted market prices as traded on the exchanges. The composition of these securities as of October 31, 2015 and 2014 is as follows.

	2015		2014	
In thousands	Cost	Fair Value	Cost	Fair Value
Current trading securities:				
Money markets	**$ 51**	**$ 51**	$ 22	$ 22
Mutual funds	**114**	**185**	106	192
Total current trading securities	**165**	**236**	128	214
Noncurrent trading securities:				
Money markets	**465**	**465**	447	447
Mutual funds	**3,625**	**4,201**	2,598	3,280
Total noncurrent trading securities	**4,090**	**4,666**	3,045	3,727
Total trading securities	**$ 4,255**	**$ 4,902**	$ 3,173	$ 3,941

Issuances and Repurchases of Common Stock

As discussed in Note 7 to the consolidated financial statements, from time to time we may repurchase shares on the open market and such shares are then canceled and become authorized but unissued shares. It is our policy to issue new shares for share-based employee awards and shareholder and employee investment plans. We present net shares issued under these awards and plans in “Common Stock Issued” in the Consolidated Statements of Stockholders’ Equity. Shares withheld by us to satisfy tax withholding obligations related to the vesting of shares awarded under the Incentive Compensation Plan have been immaterial to date.

Asset Retirement Obligations

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

We have costs of removal that are non-legal obligations as defined by the accounting guidance. The costs of removal are a component of our depreciation rates in accordance with long-standing regulatory treatment. Because these estimated removal costs meet the requirements of rate-regulated accounting guidance, we have accounted for these non-legal AROs in "Regulatory Liabilities" as presented in Note 3 to the consolidated financial statements. 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. For further discussion of these costs of removal as a component of depreciation, see "Utility Plant and Depreciation" in this Note 1.

We apply the accounting guidance for conditional AROs that requires recognition of a liability for the fair value of conditional AROs when incurred if the liability can be reasonably estimated. The NCUC, the PSCSC and the TRA have approved placing these ARO costs in deferred accounts to preserve the regulatory treatment of these costs; therefore, accretion is not reflected in the Consolidated Statements of Comprehensive Income as the regulatory treatment provides for deferral of the accretion as a regulatory asset with a corresponding deferral of the accretion recorded as a regulatory liability. AROs are capitalized concurrently by increasing the carrying amount of the related asset by the same amount as the regulatory liability. In periods subsequent to the initial measurement, any changes in the liability resulting from the passage of time (accretion) or due to the revisions of either timing or the amount of the originally estimated cash flows to settle conditional AROs must be recognized. The estimated cash flows to settle conditional AROs are discounted using the credit adjusted risk-free rate, which ranged from 4.62% to 5.89% with a time value weighted average of 5.69% for the twelve months ended October 31, 2015. We have recorded a liability on our distribution and transmission mains and services.

The cost of removal obligations recorded in the Consolidated Balance Sheets as of October 31, 2015 and 2014 are presented below.

In thousands	2015	2014
Regulatory non-legal AROs	**$ 521,478**	$ 506,574
Conditional AROs	**19,712**	14,647
Total cost of removal obligations	**$ 541,190**	$ 521,221

A reconciliation of the changes in conditional AROs for the year ended October 31, 2015 and 2014 is presented below.

In thousands	2015	2014
Beginning of period	**$ 14,647**	$ 27,016
Liabilities incurred during the period	**4,663**	2,108
Liabilities settled during the period	**(5,563)**	(3,576)
Accretion	**924**	1,548
Adjustment to estimated cash flows	**5,041**	(12,449)
End of period	**$ 19,712**	$ 14,647

Unamortized Debt Expense

Unamortized debt expense consists of costs, such as underwriting and broker dealer fees, discounts and commissions, legal fees, accountant fees, registration fees and rating agency fees, related to issuing long-term debt and the short-term syndicated revolving credit facility. We amortize long-term debt expense on a straight-line basis, which approximates the effective interest method, over the life of the related debt with lives ranging from 5 to 30 years. With the adoption of new accounting guidance in our fourth quarter of 2015 to present debt issuance costs as a direct deduction from the carrying amount of that debt, long-term debt is now presented net of unamortized debt expenses in the accompanying Consolidated Balance Sheets. For further information on the effects on regulatory assets and our long-term debt, see Note 3 and Note 5, respectively, to the consolidated financial statements.

We amortize bank debt expense over the life of the syndicated revolving credit facility, which is 5 years.

Should we reacquire long-term debt prior to its term date and simultaneously issue new debt, we defer the gain or loss resulting from the transaction, essentially the remaining unamortized debt expense, and amortize it over the life of the new debt in accordance with established regulatory practice. Where the refunding of the debt is not simultaneous, we defer the gain or loss resulting from the reacquisition of the debt as a regulatory asset or liability and amortize it over the remaining life of the redeemed debt in accordance with established regulatory practice. For income tax purposes, any gain or loss would be recognized as incurred.

Revenue Recognition

We record revenues when services are provided to our distribution service customers. 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 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 North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers on an annual basis independent of weather and consumption patterns. The margin decoupling mechanism provides for semi-annual rate adjustments to refund any over-collection of margin or to recover any under-collection of margin. In South Carolina, a RSA mechanism achieves the objectives of margin decoupling for residential and commercial customers with a one year lag. Under the RSA mechanism, we reset our rates in South Carolina based on updated costs and revenues on an annual basis. In South Carolina and Tennessee, a weather normalization adjustment (WNA) is calculated for residential and commercial customers during the winter heating season November through March, and in Tennessee, the months of April and October. The WNA mechanisms are designed to partially offset the impact that warmer-than-normal or colder-than-normal weather has on customer billings during the winter heating season. The WNA formulas do not ensure full recovery of approved margin during periods when customer consumption patterns vary from those used to establish the WNA factors. In all states, the gas cost portion of our costs is recoverable through PGA procedures and is not affected by the margin decoupling mechanism or the WNA mechanism.

We have integrity management riders (IMRs) in our tariffs in North Carolina, effective February 1, 2014, and in Tennessee, effective January 1, 2014, related to our ongoing system integrity programs. These IMRs provide for rate adjustments to allow us to recover and earn on those investments without the necessity of filing general rate cases. The North Carolina IMR was initially approved in December 2013 in the settlement of our 2013 general rate case and subsequently revised in November 2015. Under the revised North Carolina IMR tariff, we will make filings semi-annually each October 31 and April 30 for certain costs closed to plant through September and March, respectively, with revised rates effective the following December 1 and June 1, respectively. Under the Tennessee IMR, we file to adjust rates to be effective each January 1 based on capital expenditures related to mandated safety and integrity programs that were incurred by the previous October 31. For further discussion of the IMRs, see Note 3 to the consolidated financial statements.

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, customer mix, changes in weather during the period and the impact of the WNA or margin decoupling mechanisms, as applicable.

Secondary market revenues associated with the commodity are recognized when the physical sales are delivered based on contract or market prices. Asset management fees for storage and transportation remitted on a monthly basis are recognized as earned given the monthly capacity costs associated with the contracts involved. Asset management fees remitted in a lump sum are deferred and amortized ratably into income over the period in which they are earned, which is typically the contract term. See Note 3 to the consolidated financial statements regarding revenue sharing of secondary market transactions.

Utility sales, transportation and secondary market revenues are reported net of excise taxes, sales taxes and franchise fees. For further information regarding taxes, see "Taxes" in this Note 1.

Non-regulated merchandise and service work includes the sale, installation and/or maintenance of natural gas appliances and gas piping beyond the meter. Revenue is recognized when the sale is made or the work is performed. If the customer is eligible for and elects financing through us, the finance fee income is recognized on a monthly basis based on principal, rate and term.

Cost of Gas and Deferred Purchased Gas Adjustments

We charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms as set by the regulatory commissions in states in which we operate. Rate schedules for utility sales and transportation customers include PGA provisions that provide for the recovery of prudently incurred gas costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas. We charge our secondary market customers for natural gas based on negotiated contract terms. Under PGA provisions, charges to cost of gas are based on the amount recoverable under approved rate schedules. Within our cost of gas, we include amounts for lost and unaccounted for gas and adjustments to reflect the gains and losses associated with gas price hedging derivatives. By jurisdiction, differences between gas costs incurred and gas costs billed to customers, such that no operating margin is recognized related to these costs, are deferred and included in "Amounts due from customers" in "Regulatory Assets" or "Amounts due to customers" in

"Regulatory Liabilities" as presented in "Rate-Regulated Basis of Accounting" in Note 3 to the consolidated financial statements. We review gas costs and deferral activity periodically (including deferrals under the margin decoupling and WNA mechanisms) and, with regulatory commission approval, increase rates to collect under-recoveries or decrease rates to refund over-recoveries over a subsequent period.

Taxes

We have two categories of income taxes in the Consolidated Statements of Comprehensive Income: current and deferred. Current income tax expense consists of federal and state income taxes less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year. Deferred taxes are primarily attributable to utility plant, deferred gas costs, revenues and cost of gas, equity method investments, benefit of loss carryforwards and employee benefits and compensation. The determination of our provision for income taxes requires judgment, the use of estimates and the interpretation and application of complex tax laws. Judgment is required in assessing the timing and amounts of deductible and taxable items.

Deferred income taxes are determined based on the estimated future tax effects of differences between the book and tax basis of assets and liabilities. We have provided valuation allowances to reduce the carrying amount of deferred tax assets to amounts that are more likely than not to be realized. To the extent that the establishment of deferred income taxes is different from the recovery of taxes through the ratemaking process, the differences are deferred in accordance with rate-regulated accounting provisions, and a regulatory asset or liability is recognized for the impact of tax expenses or benefits that will be collected from or refunded to customers in different periods pursuant to rate orders.

Deferred investment tax credits, including energy credits, associated with our utility operations are presented in the Consolidated Balance Sheets. We amortize these deferred investment and energy tax credits to income over the estimated useful lives of the property to which the credits relate.

We recognize accrued interest and penalties, if any, related to uncertain tax positions as operating expenses in the Consolidated Statements of Comprehensive Income. This is consistent with the recognition of these items in prior reporting periods.

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 and other miscellaneous taxes.

Consolidated Statements of Cash Flows

With respect to cash overdrafts, book overdrafts are included within operating cash flows while any bank overdrafts are included with financing cash flows.

Accounting Standards Update (ASU) - Guidance Adopted in Fiscal Year 2015

Guidance	Description	Effective date	Effect on the financial statements or other significant matters
ASU 2015-03, April 2015, *Interest: Imputation of Interest - Simplifying the Presentation of Debt Issuance Costs (Subtopic 835-30)*	The guidance is part of the Financial Accounting Standards Board's (FASB) simplification initiative to reduce complexity in accounting standards. The amendment requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this amendment.	Annual periods beginning after December 15, 2015, and interim periods within those fiscal years, with early adoption permitted for financial statements that have not been previously issued. While the guidance would have been effective for us beginning November 1, 2016, we elected to adopt this guidance effective August 1, 2015.	The adoption of this guidance had no impact on our results of operations or cash flows. We retrospectively changed the presentation of the balance sheet line items current and noncurrent "Regulatory assets," "Other noncurrent assets" and "Long-term debt, net."
ASU 2015-15, August 2015, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements - Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting*	The guidance provides clarification to ASU 2015-03 for debt issuance costs for line-of-credit arrangements, specifically that the SEC would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement.	Effective upon adoption of ASU 2015-03, as adopted August 1, 2015.	The adoption of this guidance had no impact on our results of operations or cash flows.
ASU 2015-07, May 2015, *Fair Value Measurement: Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent) (Topic 820)*	The guidance amends the required disclosure of investments for which fair value is measured at NAV per share (or its equivalent). The amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the NAV per share practical expedient.	Annual periods beginning after December 15, 2015, and interim periods within those fiscal years, with retrospective application to all periods presented and early adoption permitted. While the guidance would have	The adoption of this guidance had no impact on our financial position, results of operations or cash flows. We have disclosed certain benefit plan assets under the new guidance.

		been effective for us beginning November 1, 2016, we elected to adopt this guidance effective August 1, 2015.	

Guidance	Description	Effective date	Effect on the financial statements or other significant matters
ASU 2015-12, July 2015, *Plan Accounting: Defined Benefit Pension Plans (Topic 960), Defined Contribution Pension Plans (Topic 962) and Health and Welfare Benefit Plans (Topic 965)*	The FASB issued a three-part standard providing guidance on certain aspects of the accounting by employee benefit plans. The ASU: (1) requires a pension plan to use contract value as the only measure for fully benefit-responsive investment contracts; (2) simplifies and increases the effectiveness of the investment disclosure requirements for employee benefit plans by grouping investments by general type; and (3) provides benefit plans with a measurement-date practical expedient on a month-end date nearest to the employer's fiscal year end.	Annual periods beginning after December 15, 2015 with early adoption permitted. The amendments in parts (1) and (2) are retrospectively applied to all periods presented, while the amendment in part (3) is applied prospectively. While the guidance would have been effective for us beginning November 1, 2016, we elected to adopt this guidance effective August 1, 2015.	The adoption of this guidance had no impact on our financial position, results of operations or cash flows. We have disclosed certain benefit plan assets under the new guidance of part (2). Parts (1) and (2) are applicable to our future Form 11-K filing; part (3) is not applicable to us.

Recently Issued Accounting Guidance

Guidance	Description	Effective date	Effect on the financial statements or other significant matters
ASU 2014-09, May 2014, *Revenue from Contracts with Customers (Topic 606)*	Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers. An entity may choose to adopt the new standard on either a full retrospective basis (practical expedients available) or through a cumulative effect adjustment to retained earnings as of the start of the first period of adoption.	Annual periods beginning after December 15, 2017 (beginning November 1, 2018 for us) and interim periods within that period, with early adoption permitted for annual periods beginning after December 15, 2016.	We are currently evaluating the effect on our financial position, results of operations and cash flows, as well as the transition approach we will take. The evaluation includes identifying revenue streams by like contracts to allow for ease of implementation. In our evaluation, we are following the efforts of an accounting utility subgroup and its issuance of a revenue implementation guide.
ASU 2014-15, August 2014, *Presentation of Financial Statements - Going Concern (Subtopic 205-40)*	The amendment provides guidance on determining when and how reporting entities must disclose going concern uncertainties in their financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date of issuance of the entity's financial statements. An entity must provide certain disclosures	Annual periods ending after December 15, 2016 (October 31, 2017 for us), and interim and annual periods thereafter; early adoption is permitted.	The adoption of this guidance will have no impact on our financial position, results of operations or cash flows. It will require establishing a going concern assessment process to meet the standard.

	if there is a "substantial doubt about the entity's ability to continue as a going concern."		

Guidance	Description	Effective date	Effect on the financial statements or other significant matters
ASU 2015-05, April 2015, *Intangibles - Goodwill and Other - Internal-Use Software: Customer's Accounting for Fees Paid in a Cloud Computing Arrangement (Subtopic 350-40)*	The guidance amends ASC 350-40 to provide customers with guidance on determining whether a cloud computing arrangement contains a software license that should be accounted for as internal-use software. The guidance applies only to hosting arrangements if both of the following criteria are met: (a) the customer has the contractual right to take possession of the software at any time during the hosting period without significant penalty and (b) it is feasible for the customer to run the software on its own hardware or contract with another party to host the software.	Annual periods (and interim periods within those periods) beginning after December 15, 2015 (November 1, 2016 for us), with early adoption permitted. Entities may adopt the guidance retrospectively or prospectively to arrangements entered into, or materially modified, after the effective date.	We are currently evaluating the effect on our financial position, results of operations and cash flows.
ASU 2015-17, November 2015, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*	The guidance eliminates the current requirement to present deferred tax assets and liabilities as current and noncurrent amounts in a classified balance sheet. The new standard requires deferred tax liabilities and assets be classified as noncurrent. The current requirement that deferred tax liabilities and assets be presented as a single amount remains unchanged.	Annual periods (and interim periods within those periods) beginning after December 15, 2016, early adoption is permitted.	The adoption of this guidance will have no impact on our results of operations or cash flows. The reclassification of amounts from current to noncurrent will affect presentation of our financial position.

Reclassifications and Changes in Presentation

Reclassifications have been made to the prior year Consolidated Balance Sheets to conform with the current year presentation. We early adopted ASU 2015-03 requiring that issuance costs related to a long-term debt issuance be presented as a direct deduction from the carrying amount of that debt. In prior years, we presented unamortized debt expense as current and noncurrent regulatory assets. While these amounts are not regulatory assets under accounting guidance, they are a critical component of the embedded cost of debt financing and cost of capital utilized in rate proceedings in each of our jurisdictions. With the adoption of the new pronouncement, unamortized debt expense associated with outstanding long-term debt has been reclassified from current and noncurrent regulatory assets to a reduction of the carrying value of long-term debt as of October 31, 2015 and 2014. For further information on the impact to our presentation of regulatory assets and long-term debt, see Note 3 and Note 5, respectively, to the consolidated financial statements.

Reclassifications have been made to the prior years Consolidated Statements of Cash Flows to conform with the current year presentation to provide additional detail and to present such information within separate line items. Within “Cash Flows from Operating Activities," we have changed the prior presentation of the cash flows line item "Allowance for doubtful accounts," comprised of the provision and the charge-offs. The provision is now presented on a separate line item "Provision for doubtful accounts" and the charges-offs are now included in the line item "Receivables, net." We have also changed the prior presentation of the cash flows line item "Provision for postretirement benefits, net" comprised of the contributions to benefit plans and other activity. The contributions are now presented on a separate line item "Contributions to benefit plans" and the remaining activity is now presented on a separate line item "Accrued/deferred postretirement benefit costs." The presentation for 2014 and 2013 have been changed to conform to the current year presentation. The reclassifications that provide additional detail had no effect on previously reported amounts for net cash flows from operating, investing or financing activities.

2. Proposed Acquisition by Duke Energy Corporation

On October 24, 2015, we entered into a Merger Agreement with Duke Energy and Forest Subsidiary, Inc. (Merger Sub), a new wholly owned subsidiary of Duke Energy. The Merger Agreement provides for the merger of the Merger Sub with and into Piedmont, with Piedmont surviving as a wholly owned subsidiary of Duke Energy (the Acquisition). At the effective time of the Acquisition, subject to receipt of required shareholder and regulatory approvals and meeting specified customary closing conditions, each share of Piedmont common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $60 in cash per share, without interest, less any applicable withholding taxes. Upon consummation of the Acquisition, Piedmont common stock will be delisted from the New York Stock Exchange (NYSE).

Completion of the Acquisition is subject to various closing conditions, including, among others (i) the approval of the Merger Agreement by an affirmative vote of the holders of a majority of the outstanding shares of our common stock, (ii) approval from the NCUC, and (iii) expiration or termination of any applicable waiting period under the federal Hart-Scott-Rodino Antitrust Improvements Act of 1976. The Merger Agreement may be terminated by us or by Duke Energy if the Acquisition is not consummated by October 31, 2016, subject to a six-month extension by either of us under certain circumstances. The Merger Agreement contains certain termination rights for both companies under certain circumstances, and provides that, upon termination of the Merger Agreement under specified circumstances, we would be required to pay Duke Energy a termination fee of $125 million, or Duke Energy would be required to pay us a termination fee of $250 million.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to completion of the Acquisition. Among other restrictions, the Merger Agreement limits our total capital spending, limits the extent to which we can obtain financing through long-term debt and equity, and caps our cash dividend to no more than the current annual per share dividend plus an increase of not more than $.04 per fiscal year, with record dates and payment dates consistent with our current dividend practices. Also, provision is made for a stub period dividend payment to holders of record of our shares of common stock immediately prior to consummation of the Acquisition.

In connection with this transaction, we recorded Acquisition-related expenses of $8.6 million for costs paid to outside parties in fiscal 2015, which are reflected in "Operations and maintenance" in "Operating Expenses" in the Consolidated Statements of Comprehensive Income. This amount does not include the cost of company personnel participating in Acquisition-related activities. We also recorded incremental share-based compensation expense of $7.2 million in "Operations and maintenance" as noted above for the end of period remeasurement to market value of the incentive compensation awards and the retention award of our President and Chief Executive Officer based upon the increase in the trading price of our common stock since the announcement of the Acquisition. We treated these costs as tax deductible since the requisite closing conditions to the Acquisition have not yet been satisfied. Upon completion of the Acquisition, we will evaluate the tax deductibility of these costs and reflect any non-deductible amounts in the effective tax rate at the Acquisition closing date. For further information on our employee share-based plans, see Note 11 to the consolidated financial statements.

3. Regulatory Matters

Rate-Regulated Basis of Accounting

Regulatory assets and liabilities in the Consolidated Balance Sheets as of October 31, 2015 and 2014 are as follows.

In thousands	2015	2014
Regulatory Assets:		
Current:		
Unamortized debt expense on reacquired debt	$ 238	$ 239
Amounts due from customers	—	16,108
Environmental costs	1,513	1,568
Deferred operations and maintenance expenses	847	916
Deferred pipeline integrity expenses	3,470	3,470
Deferred pension and other retirement benefit costs	2,757	2,769
Robeson LNG development costs	381	917
Other	1,730	1,850
Total current	10,936	27,837
Noncurrent:		
Unamortized debt expense on reacquired debt	4,666	4,904
Environmental costs	5,107	6,470
Deferred operations and maintenance expenses	3,997	4,721
Deferred pipeline integrity expenses	29,824	24,694
Deferred pension and other retirement benefits costs	17,861	18,799
Amounts not yet recognized as a component of pension and other retirement benefit costs	114,854	94,265
Regulatory cost of removal asset	19,087	18,275
Robeson LNG development costs	127	509
Other	1,203	1,644
Total noncurrent	196,726	174,281
Total	$ 207,662	$ 202,118
Regulatory Liabilities:		
Current:		
Amounts due to customers	$ 13,367	$ 46,231
Noncurrent:		
Regulatory cost of removal obligations	521,478	506,574
Deferred income taxes	68,738	51,930
Amounts not yet recognized as a component of pension and other retirement benefit costs	85	94
Total noncurrent	590,301	558,598
Total	$ 603,668	$ 604,829

The 2014 presentation of unamortized debt expense has been changed to conform with the current year presentation in the table above. As discussed in Note 1 to the consolidated financial statements, we early adopted ASU

2015-03 requiring that issuance costs related to a recognized long-term debt liability be presented in the balance sheet as a direct deduction from the carrying value of that debt. Consequently, unamortized debt expense of $.9 million current and $9 million noncurrent presented in 2014 as regulatory assets have been reclassified as a reduction of $9.9 million to the carrying value of long-term debt. The amounts presented above in line items "Unamortized debt expense on reacquired debt" represent unamortized debt expense associated with the early retirement or the refunding of debt in accordance with established regulatory practice. Unamortized debt expenses related to short-term bank debt and unallocated expenses of our open debt and equity shelf registration are now presented in the line item "Other noncurrent assets" as "Noncurrent Assets" in the Consolidated Balance

Sheets. See Note 1 with discussion of "Unamortized Debt Expense" and Note 5 to the consolidated financial statements for related discussion of these presentation changes.

As of October 31, 2015, we have $19.1 million of AROs and $117 million of other regulatory assets on which we do not earn a return. Included in deferred pension and other retirement costs are amounts related to pension funding for our Tennessee jurisdiction. The recovery of these amounts is authorized by the TRA on a deferred cash basis.

Regulatory Oversight and Rate and Regulatory Actions

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 long-term debt and equity securities.

The NCUC and the PSCSC regulate our gas purchasing practices under a standard of prudence and audit our gas cost accounting practices. The TRA regulates our gas purchasing practices under a gas supply incentive program which compares our actual costs to market pricing benchmarks. As part of this jurisdictional oversight, all three regulatory commissions address our gas supply hedging activities. Additionally, all three regulatory commissions allow for recovery of uncollectible gas costs through the PGA. The portion of uncollectibles related to gas costs is recovered through the deferred account and only the non-gas costs, or margin, portion of uncollectibles is included in base rates and uncollectibles expense.

North Carolina

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

The NCUC had allowed EasternNC to defer its O&M expenses during the first eight years of operation or until the first rate case order, whichever occurred first, with the deferred amounts accruing interest 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. Under the settlement of the 2008 general rate proceeding, the unamortized balance of the EasternNC deferred O&M expenses of $9 million at October 31, 2008 was to be amortized over a twelve year period beginning November 1, 2008, with interest accruing at 7.84% per annum. Under the settlement of the 2013 general rate proceeding discussed below, the unamortized balance of the EasternNC deferred O&M expenses was $6.3 million as of December 31, 2013. This balance is accruing interest at a rate of 6.55% per annum with amortization beginning January 1, 2014 over an 82-month period ending October 31, 2020. As of October 31, 2015 and 2014, we had unamortized balances, including accrued interest, of $4.8 million and $5.6 million, respectively.

We incur certain pipeline integrity management costs in compliance with the Pipeline Safety Improvement Act of 1992 and certain regulations of the United States Department of Transportation. The NCUC approved deferral treatment of the O&M costs applicable to certain incremental pipeline integrity external expenditures beginning November 1, 2004. The approved balance for recovery of actual pipeline integrity management O&M costs incurred between July 1, 2008 through August 31, 2013 as established in the settlement of the 2013 general rate proceeding discussed below was $17.3 million to be amortized over a five-year period from January 1, 2014 through December 31, 2018. As of October 31, 2015 and 2014, we had unamortized regulatory asset balances for deferred pipeline integrity expenses of $33.3 million and $28.2 million, respectively. The existing regulatory asset treatment for ongoing pipeline integrity management costs is expected to continue until another recovery mechanism is established in a future rate proceeding.

With the approval of the settlement of the 2013 NCUC general rate proceeding discussed below, certain capital expenditures that are incurred to comply with federal pipeline safety and integrity requirements will be separately tracked and recovered on an annual basis through an IMR, as revised by a subsequent settlement approved by the NCUC in November

2015. The settlement also approved recovery of $6.3 million of deferred North Carolina environmental costs over a five-year period from January 2014 through December 2018.

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

In November 2013, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2013. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In November 2014, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2014. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

In November 2015, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2015. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

Our gas cost hedging plan for North Carolina is designed to provide a level of protection against significant price increases, targets a percentage range up to 45% 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 is a reduction in or an addition to gas costs, respectively, which, along with any hedging expenses, are flowed through to North Carolina customers in rates. The gas cost review orders issued November 2013, November 2014 and November 2015 found our hedging activities during the review periods to be reasonable and prudent.

In April 2013, we withdrew a petition that had been filed with the NCUC in October 2012 requesting authority to transfer the total balance of $6.7 million of capital costs held in "Plant held for future use" in "Utility Plant" in the Consolidated Balance Sheets to a deferred regulatory asset account, citing our intent to address the matter in a general rate application. The balance in "Plant held for future use" was comprised of real estate and non-real estate costs and related to the development of a LNG facility in Robeson County, North Carolina, construction of which was suspended by Piedmont in March 2009. The appropriate treatment of the Robeson County LNG costs was addressed in the general rate settlement discussed below.

In May 2013, we filed a general rate application with the NCUC requesting an increase in rates and charges. In December 2013, the NCUC approved our general rate case settlement agreement with the NCUC Public Staff with new rates effective January 2014. In its order, the NCUC approved the following:

- Updated and increased rates and charges based on an overall rate base of $1.8 billion, an equity capital structure component of 50.7% and a return on common equity of 10% and an overall rate of return of 7.51%.
- Increased total annual revenues of $30.7 million, a 3.58% increase in total revenues, or .7% annual increase, including $16.8 million related to gas utility margin and $13.8 million related to increased fixed gas costs, and annual pre-tax income of $24.2 million after taking into account revised depreciation rates and changes to regulatory asset amortizations.
- Implementation of a new IMR designed to separately track and recover annually outside of general rate cases the costs associated with capital expenditures incurred to comply with federal pipeline safety and integrity requirements.
- Implementation of lower depreciation rates that provide increased annual pre-tax income of $10.9 million. These new lower rates reflect the most recent study conducted in 2009, as discussed in Note 1 to the consolidated financial statements.
- Amortization and collection of $1.2 million of certain non-real estate costs associated with the initial development of the Robeson County LNG facility as discussed above.
- Amortization and collection of certain environmental expenses and pipeline safety and integrity compliance expenses through August 31, 2013 that had been deferred since our last general rate case in 2008.
- Provision for ongoing increased annual contributions to fund pipeline safety and integrity research.

- Future adjustments to rates to recognize the lower state corporate income taxes from North Carolina legislation for fiscal years beginning November 1, 2014 and November 1, 2015.

In January 2014, we filed a petition with the NCUC seeking authority to adjust rates effective February 1, 2014 under the IMR mechanism approved in the general rate case settlement agreement in December 2013 discussed above. The IMR provided for annual adjustments to our rates every February 1 for capital investments in integrity and safety projects as of October 31 of the preceding year. In February 2014, the NCUC approved as filed the initial IMR adjustment totaling $.8

million in annual margin revenues that we reflected in our rates to customers beginning that month. In December 2014, we filed a petition with the NCUC seeking authority to adjust rates to collect an additional $26.6 million in annual IMR margin revenues effective February 1, 2015 based on $241.9 million of capital investments in integrity and safety projects over the twelve-month period ending October 31, 2014. In January 2015, the NCUC issued an order authorizing the requested IMR rate adjustments, subject to further review and determination of the reasonableness and prudence of the capital investments and associated costs reflected in the adjustments in our annual IMR adjustment proceedings or next general rate case, with any adjustments to be implemented through a prospective rate adjustment at or after the time such adjustment is approved by the NCUC. We subsequently engaged in discussions with the NCUC Public Staff regarding the completion of their review of the IMR costs and the development of a future procedural schedule for the IMR audit and rate approval process. In September 2015, we and the NCUC Public Staff filed an agreement with the NCUC seeking approval of the following stipulations regarding the operation of the IMR:

- Semi-annual IMR rate adjustments each December 1 and June 1, starting December 1, 2015, based on eligible capital investments in integrity and safety projects closed to plant as of September 30 and March 31.
- Extension of the IMR tariff from October 31, 2017 to October 31, 2019.
- An established procedural process and time line for NCUC Public Staff's annual review of our IMR filings.
- Fixed percentages to quantify various classes of system integrity expenditures to be recovered through the IMR with the remaining to be recovered through a future rate case:
    - Transmission integrity: 85% IMR / 15% rate case.
    - Distribution integrity: 90% IMR / 10% rate case.
    - Right-of-way clearing for integrity projects: 15% IMR / 85% rate case.
    - Work and asset management system: 68% IMR / 32% rate case.
- Tax-related adjustments.
- An immaterial reduction in IMR margin, which we recorded in the fourth fiscal quarter of 2015.

Based on the IMR agreement, in November 2015, we filed a petition with the NCUC seeking authority to adjust rates to collect an additional $13.4 million in annual IMR margin revenues, effective December 1, 2015, based on $161.9 million of IMR-eligible capital investments in integrity and safety projects over the eleven-month period ended September 30, 2015. In November 2015, the NCUC approved the IMR settlement agreement and the requested December 2015 IMR rate increase.

In April 2014, we filed a petition with the NCUC for a limited waiver of certain billing provisions of our tariff related to emergency service and unauthorized gas taken by customers in January 2014. In August 2014, we and the NCUC Public Staff filed a joint stipulation of settlement. The terms of the settlement included the granting of a waiver of the commodity index pricing mechanism for January 2014, that we should not be penalized for our conduct in varying from the tariff in this instance as that conduct was solely for the benefit of our customers, and that we and the NCUC Public Staff would work together to develop mutually agreeable revisions to our tariff to address the situation that led to this petition. In October 2014, the NCUC issued an order rejecting the joint stipulation of settlement, finding that we must bill our customers for the higher commodity cost of gas pursuant to tariffs and assessing a $65,000 penalty against us for failure to bill and collect according to the commission-approved tariffs. The order further required us to engage in discussions with each customer served under an interruptible rate schedule to explain the service and obligation under that rate schedule and to conduct an investigation to determine if customers are receiving service under the appropriate tariff.

In April 2014, the NCUC issued an order granting us the authority to issue up to $1 billion in the aggregate of senior or subordinated debt securities or equity securities under our open shelf registration statement. This request was made by us to allow flexibility to access the capital markets as needed for business purposes, including for capital investments and to fund the operations of our subsidiaries. For further information on this shelf registration statement, see Note 5 to the consolidated financial statements.

In March 2015, we filed a petition with the NCUC seeking authority for a one-time gas cost bill credit, including applicable sales taxes, for our retail sales and transportation customers in North Carolina. In March 2015, the NCUC issued an order approving our request. The bill credit of $45.5 million was reflected on customers' April 2015 bills, reducing amounts due to customers in North Carolina.

South Carolina

We currently operate under the Natural Gas Rate Stabilization Act of 2005 in South Carolina. If a utility elects to operate under this act, the annual cost and revenue filing will provide that the utility's rate of return on equity will remain within a 50-basis point band above or below the last approved allowed rate of return on equity.

In June 2012, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2012 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in October 2011. In October 2012, the PSCSC issued an order approving a settlement agreement between the Office of Regulatory Staff (ORS) and us that resulted in a $1.1 million annual decrease in margin based on a stipulated return on equity of 11.3%, effective November 1, 2012.

In June 2013, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2013 and a cost and revenue study as permitted by the RSA requesting a change in rates from those approved by the PSCSC in October 2012. In October 2013, the PSCSC issued an order approving a settlement agreement between the ORS and us that resulted in a $.1 million annual decrease in margin based on a stipulated return on equity of 11.3%, effective November 1, 2013. The PSCSC also approved the recovery of $.2 million of our deferred South Carolina environmental costs over a one-year period beginning November 2013 and ending October 2014.

In June 2014, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2014 and a cost and revenue study under the RSA requesting a change in rates from those approved by the PSCSC in October 2013. In October 2014, the PSCSC issued an order approving a settlement agreement between the ORS and us that resulted in a $2.9 million annual decrease in margin based on a stipulated allowed return on equity of 10.2%, effective November 1, 2014. Also in this proceeding, the PSCSC approved the recovery of $.1 million of our deferred South Carolina environmental costs and $.5 million of certain non-real estate costs associated with the initial development of the Robeson County LNG facility located in North Carolina as discussed above, both with amortization periods of one year beginning November 2014 and ending October 2015.

In June 2015, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2015 and a cost and revenue study under the RSA requesting a change in rates from those approved by the PSCSC in the October 2014 order. In October 2015, the PSCSC issued an order approving a settlement agreement between the ORS and us that resulted in a $1.65 million annual increase in margin based on a stipulated allowed return on equity of 10.2%, effective November 1, 2015.

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

The PSCSC has approved a gas cost hedging plan for the purpose of cost stabilization for South Carolina customers. The plan targets a percentage range up to 45% of annual normalized sales volumes for South Carolina and operates using historical pricing indices 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 recovered in rates as gas costs. Any gain or loss recognized under the hedging program is a reduction in or an addition to gas costs, respectively, and flows through to South Carolina customers in rates. In an August 2011 order, the PSCSC approved a stipulation that our hedging program should no longer have a required minimum volume of hedging.

In August 2013, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2013.

In August 2014, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2014.

In September 2015, the PSCSC approved our PGAs and found our gas purchasing policies to be prudent for the twelve months ended March 31, 2015.

In July 2014, we filed a petition with the PSCSC requesting a limited waiver of certain billing provisions of our tariff related to emergency service for customers in January 2014. In August 2014, the PSCSC granted our request and ordered us to continue to collaborate with the ORS to revise our tariff to address the situation that led to this petition.

Tennessee

In Tennessee, we operate under the Tennessee Incentive Plan (TIP) that benchmarks gas costs against amounts determined by published market indices and by sharing secondary market (capacity release and off-system sales) activity performance. Under the TIP, the TRA established an allocation of secondary marketing gains and losses to ratepayers and shareholders with a uniform 75/25 sharing ratio with a $1.6 million annual incentive cap for us on these gains and losses. The

TIP includes procedures for asset management transactions and provides for a triennial review of TIP operations by an independent consultant. Although the TIP replaced annual prudence reviews of our gas purchasing activities, we undergo an annual compliance audit on the accuracy of our calculations and compliance with all TRA orders and directives regarding the calculation of our deferred gas cost account balances under the Actual Cost Adjustment (ACA) mechanism.

In August 2012, we filed an annual report with the TRA reflecting the shared gas cost savings from gains and losses derived from gas purchase benchmarking and secondary market transactions for the twelve months ended June 30, 2012 under the TIP. In February 2013, the TRA Utilities Division Audit Staff (Audit Staff) submitted their report with which we concurred. In March 2013, the TRA approved the TIP account balances and issued its written order approving our TIP account balances.

In August 2013, we filed an annual report with the TRA reflecting the shared gas cost savings from gains and losses derived from gas purchase benchmarking and secondary market transactions for the twelve months ended June 30, 2013 under the TIP. In February 2014, the Audit Staff submitted their report with which we concurred. In March 2014, the TRA approved and adopted the Audit Staff's report. The TRA's written order was issued in April 2014.

In August 2014, we filed an annual report with the TRA reflecting the shared gas cost savings from gains and losses derived from gas purchase benchmarking and secondary market transactions for the twelve months ended June 30, 2014 under the TIP. In March 2015, the Audit Staff submitted their report with which we concurred. In April 2015, the TRA approved and adopted the Audit Staff's report. The TRA's written order was issued in May 2015.

In August 2015, we filed an annual report with the TRA reflecting the shared gas cost savings from gains and losses derived from gas purchase benchmarking and secondary market transactions for the twelve months ended June 30, 2015 under the TIP. We are waiting on a ruling from the TRA at this time.

In September 2012, we filed an annual report for the twelve months ended June 30, 2012 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. In March 2013, the TRA approved the deferred gas cost account balances and issued its written order.

In August 2013, we filed a petition with the TRA to authorize us to make an adjustment to the deferred gas cost account reporting for prior periods in the amount of a $3.7 million under collection. In November 2014, we filed a joint settlement agreement with the TRA staff and the Tennessee Attorney General's Consumer Advocate and Protection Division (CAD) in which the parties agreed that we may include in our next ACA filing prior period adjustments totaling $2 million in lieu of the $3.7 million as originally petitioned. In September 2014, we recorded as expense $1.7 million in the Consolidated Statements of Comprehensive Income. In December 2014, the TRA approved the settlement agreement, and we included the stipulated $2 million of prior period adjustments in the ACA annual report filed in December 2014 for the twelve-month period ended June 30, 2013. In January 2015, the TRA issued its written order approving the settlement agreement. In October 2015, the TRA approved the deferred gas cost account balances for the twelve-month period ended June 30, 2013 and issued its written order.

In November 2015, we filed an annual report for the twelve months ended June 30, 2014 with the TRA that reflected the transactions in the deferred gas cost account for the ACA mechanism. We are waiting on a ruling from the TRA at this time.

In September 2011, we filed a general rate application with the TRA requesting authority for an increase to rates and charges, proposed to be effective March 1, 2012. In addition, the petition also requested modifications of the cost allocation and rate designs underlying our existing rates, including shifting more of our cost recovery to our fixed charges and expanding the period of the WNA to October through April. We also sought approval to implement a school-based energy education program with appropriate cost recovery mechanisms, amortization of certain regulatory assets and deferred accounts, revised depreciation rates for plant and changes to the existing service regulations and tariffs. In December 2011, we and the CAD reached a stipulation and settlement agreement resolving all issues in this proceeding, including an increase in rates and charges to all customers effective March 1, 2012 designed to produce overall incremental revenues of $11.9 million annually, or 6.3% above the current annual revenue, based upon an approved rate of return on equity of 10.2%. The new cost allocation and rate designs shifted recovery of fixed charges from 29% to 37% with a resulting decrease of volumetric charges from 71% to 63%. The stipulation and settlement agreement did not include a cost recovery mechanism for a school-based energy education program. In January 2012, a hearing on this matter was held by the TRA. The TRA approved the settlement agreement at the January 2012 hearing. The TRA issued its written order in April 2012.

As a part of the rate case settlement mentioned above, the TRA approved the recovery of $1 million incurred as a result of our response to severe flooding in Nashville in May 2010. These direct incremental expenses had been approved for deferred accounting treatment in October 2010. These deferred expenses are being amortized over eight years beginning March 1, 2012 through February 2020.

In August 2013, we filed a petition with the TRA seeking authority to implement an IMR to recover the costs of our capital investments that are made in compliance with federal and state safety and integrity management laws or regulations. We proposed that the rider be effective October 1, 2013 with an initial adjustment on January 1, 2014 of $13.1 million in annual margin revenue from tariff customers based on capital expenditures of $100.4 million incurred through October 2013 and for rates to be updated annually outside of general rate cases for the return of and on these capital investments. In September 2013, the TRA issued an order suspending this proposed tariff through December 30, 2013. In November 2013, we and the CAD filed an IMR settlement with the TRA. A hearing on this matter was held in December 2013, and the TRA approved the IMR settlement as filed for $13.1 million with the IMR rate adjustments beginning January 2014. A written order was issued in May 2014. In December 2014, we filed a petition with the TRA seeking authority to collect an additional $6.5 million in annual IMR margin revenues effective January 2015 based on $54 million of capital investments in integrity and safety projects over the twelve-month period ended October 31, 2014. In January 2015, the TRA accepted and approved the requested IMR rate adjustment and issued its written order in February 2015. In November 2015, we filed a petition with the TRA seeking authority to collect an additional $1.7 million in annual margin revenue effective January 2016 based on $18.4 million of capital investments in integrity and safety projects over the twelve-month period ending October 31, 2015. In December 2015, the TRA approved the IMR rate increase to be effective January 2016. We are waiting on the TRA's written order at this time.

In February 2014, we filed a petition with the TRA to authorize us to amortize and refund $4.7 million to customers for recorded excess deferred taxes. We proposed to refund this amount to customers over three years. In November 2015, we filed a settlement agreement with the CAD stipulating that Piedmont refund the $4.7 million to customers over a twelve month period. In December 2015, the TRA approved the settlement agreement, and we will begin refunding the $4.7 million to customers through a rate decrement over the twelve month period beginning January 2016. We are waiting on the TRA's written order at this time.

In September 2014, we filed a petition with the TRA seeking authority to implement a compressed natural gas (CNG) infrastructure rider to recover the costs of our capital investments in infrastructure and equipment associated with this alternative motor vehicle transportation fuel. We proposed that the tariff rider be effective October 1, 2014 with an initial rate adjustment on November 1, 2014 based on capital expenditures incurred through June 2014 and for rates to be updated annually outside of general rate cases for the return of and on these capital investments. In November 2014, the TRA consolidated this docket with a separate petition we filed seeking modifications to our tariff regarding service to customers using natural gas as a motor fuel. A hearing on this matter was held in January 2015. In February 2015, the TRA (1) denied approval of the proposed tariff rider, (2) ruled that our retail CNG motor fuel service should be unregulated and no longer provided under our regulated tariff, and (3) approved the proposed modification to our tariff providing natural gas for motor fuel purposes at customer premises. The TRA indicated that we may seek recovery of our prior investments in CNG equipment of $4.7 million since our last rate proceeding in utility rate base in our next general rate case proceeding as the investments were made in good faith under the assumption retail CNG motor fuel would be a regulated service. The TRA's written order was issued in October 2015.

All States

Due to the seasonal nature of our business, we contract with customers in the secondary market to sell supply and capacity assets when market conditions permit. 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 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. This sharing mechanism for secondary market activity in all three jurisdictions for the twelve months ended October 31, 2015, 2014 and 2013 is presented below.

In millions	**2015**	2014	2013
Allocated to customers as gas cost reductions	**$ 60.1**	$ 72.2	$ 26.9

Margin allocated to us	**21.1**	25.4	9.0
Margin from secondary market activity	**$ 81.2**	$ 97.6	$ 35.9

6.00%, due December 19, 2033	100,000	(760)	99,240
Total	1,425,000	(10,516)	1,414,484
Less current maturities	—	—	—
Total	$ 1,425,000	$ (10,516)	$ 1,414,484

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

In thousands		
2016	$	40,000
2017		35,000
2018		—
2019		—
2020		—
Thereafter		1,500,000
Total	$	1,575,000

We had an open combined debt and equity shelf registration statement filed with the SEC in July 2011 that was available for future use until its expiration date of July 6, 2014. In February 2013, we sold shares of common stock under this registration statement. For further information on this transaction, see Note 7 to the consolidated financial statements.

In June 2014, we filed with the SEC a combined debt and equity shelf registration statement that became effective on June 6, 2014. The NCUC has approved debt and equity issuances under this shelf registration statement up to $1 billion during its three-year life. As of October 31, 2015, we have $544.1 million remaining for debt and equity issuances as approved by the NCUC. Unless otherwise specified at the time such securities are offered for sale, the net proceeds from the sale of the securities will be used to finance capital expenditures, to repay outstanding short-term, unsecured notes under our commercial paper (CP) program, to refinance other indebtedness, to repurchase our common stock, to pay dividends and for general corporate purposes.

On September 18, 2014, we issued $250 million of twenty-year, unsecured senior notes with an interest rate of 4.10% and at a discount of .174% or $435,000 under the registration statement in effect noted above. We have the option to redeem all or part of the notes before the stated maturity prior to March 18, 2034, at a redemption price equal to the greater of a) 100% of the principal amount plus any accrued and unpaid interest to the date of redemption, or b) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed, discounted to the date of redemption on a semi-annual basis at the Treasury Rate as defined in the indenture, plus 15 basis points and any accrued and unpaid interest to the date of redemption. We have the option to redeem all or part of the notes before the stated maturity on or after March 18, 2034, at 100% of the principal amount plus any accrued and unpaid interest to the date of redemption. We used the net proceeds of $247.7 million from this issuance to finance capital expenditures, to repay outstanding short-term, unsecured notes under our CP program and for general corporate purposes.

On September 14, 2015, we issued $150 million of ten-year, unsecured senior notes with an interest rate of 3.60% and at a discount of .065% or $97,500 under the registration statement in effect noted above. We have the option to redeem all or part of the notes before the stated maturity prior to June 1, 2025, at a redemption price equal to the greater of a) 100% of the principal amount plus any accrued and unpaid interest to the date of redemption, or b) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed, discounted to the date of redemption on a semi-annual basis at the Treasury Rate as defined in the indenture, plus 25 basis points and any accrued and unpaid interest to the date of redemption. We have the option to redeem all or part of the notes before the stated maturity on or after June 1, 2025, at 100% of the principal amount plus any accrued and unpaid interest to the date of redemption. We used the net proceeds of $148.9 million from this issuance to finance capital expenditures, to repay outstanding short-term, unsecured notes under our CP program and for general corporate purposes.

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, 2015, our net earnings available for restricted payments were $1.2 billion.

We are subject to default provisions related to our long-term debt and short-term borrowings. Failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. There are cross default provisions in all of our debt agreements. As of October 31, 2015, we are in compliance with all default provisions.

The default provisions of some or all of our senior debt include:

- Failure to make principal or interest payments,
- Bankruptcy, liquidation or insolvency,
- Final judgment against us in excess of $1 million that after 60 days is not discharged, satisfied or stayed pending appeal,
- Specified events under the Employee Retirement Income Security Act of 1974,
- Change in control, and
- Failure to observe or perform covenants, including:
    - Interest coverage of at least 1.75 times. Interest coverage was 3.96 times as of October 31, 2015;
    - Funded debt cannot exceed 70% of total capitalization. Funded debt was 57% of total capitalization as of October 31, 2015;
    - Funded debt of all subsidiaries in the aggregate cannot exceed 15% of total capitalization. There is no funded debt of our subsidiaries as of October 31, 2015;
    - Restrictions on permitted liens;
    - Restrictions on paying dividends on or repurchasing our stock or making investments in subsidiaries; and
    - Restrictions on burdensome agreements.

6. Short-Term Debt Instruments

At October 31, 2015, we have an $850 million five-year revolving syndicated credit facility that expires on October 1, 2017. We pay an annual fee of $35,000 plus 8.5 basis points for any unused amount. The facility provides a line of credit for letters of credit of $10 million, of which $1.6 million and $1.8 million were issued and outstanding at October 31, 2015 and 2014, respectively. These letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. The credit facility bears interest based on the 30-day London Interbank Offered Rate (LIBOR) plus from 75 to 125 basis points, based on our credit ratings. Amounts borrowed are continuously renewable until the expiration of the facility in 2017 provided that we are in compliance with all terms of the agreement. See Note 5 to the consolidated financial statements for discussion of default provisions, including cross default provisions, in all of our debt agreements.

On December 14, 2015, we entered into an agreement with the lenders under our existing $850 million five-year revolving syndicated credit facility to amend and extend the facility at substantially similar terms to our existing facility. The amended facility extended the maturity of our facility to December 14, 2020. The amended facility expressly permits the Acquisition by Duke Energy. The CP program will continue to be backstopped by the new credit facility.

We have an $850 million unsecured CP program that is backstopped by the revolving syndicated credit facility. The amounts outstanding under the revolving syndicated credit facility and the CP program, either individually or in the aggregate, cannot exceed $850 million. The notes issued under the CP program may have maturities not to exceed 397 days from the date of issuance and bear interest based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings, plus a spread of 5 basis points. Any borrowings under the CP program rank equally with our other unsecured debt. The notes under the CP program are not registered and are offered and issued pursuant to an exemption from registration. Due to the seasonal nature of our business, amounts borrowed can vary significantly during the year.

As of October 31, 2015, we had $340 million of notes outstanding under the CP program, as included in "Short-term debt" in "Current Liabilities" in the Consolidated Balance Sheets, with original maturities ranging from 7 to 14 days from their dates of issuance at a weighted average interest rate of .22%. As of October 31, 2014, our outstanding notes under the CP program, included in the Consolidated Balance Sheets as stated above, were $355 million at a weighted average interest rate of .17%.

We did not have any borrowings under the revolving syndicated credit facility for the twelve months ended October 31, 2015. A summary of the short-term debt activity under our CP program for the twelve months ended October 31, 2015 is as follows.

In thousands		
Minimum amount outstanding	$	**230,000**
Maximum amount outstanding	$	**580,000**
Minimum interest rate		**.15%**
Maximum interest rate		**.30%**
Weighted average interest rate		**.21%**

Our five-year revolving syndicated 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 57% at October 31, 2015.

7. Stockholders' Equity

Capital Stock

Changes in common stock for the years ended October 31, 2015, 2014 and 2013 are as follows.

In thousands	Shares		Amount
Balance, October 31, 2012	72,250	$	442,461
Issued to participants in the Employee Stock Purchase Plan (ESPP)	33		1,056
Issued to the Dividend Reinvestment and Stock Purchase Plan (DRIP)	720		22,791
Issued to participants in the Incentive Compensation Plan (ICP)	96		3,065
Issuance of common stock through public share offering, net of underwriting fees	3,000		92,640
Costs from issuance of common stock	—		(369)
Balance, October 31, 2013	76,099		561,644
Issued to ESPP	34		1,143
Issued to DRIP	698		23,443
Issued to ICP	100		3,315
Issuance of common stock through forward sale agreements, net of expenses	1,600		47,290
Balance, October 31, 2014	78,531		636,835
Issued to ESPP	**31**		**1,239**
Issued to DRIP	**669**		**24,679**
Issued to ICP	**130**		**4,964**
Issuance of common stock through forward sale agreements, net of expenses	**1,522**		**53,702**
Balance, October 31, 2015	**80,883**	**$**	**721,419**

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 canceled and become authorized but unissued shares available for issuance under the ESPP, DRIP and ICP.

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 at that time an amendment of the Common Stock Open Market Purchase Program to provide for the repurchase of up to four million additional shares of common stock to maintain our debt-to-equity capitalization ratios at target levels. These combined actions increased the total authorized share repurchases from three million to ten million shares. The additional four million shares were referred to as our accelerated share repurchase (ASR) program. On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated.

Under our effective combined debt and equity shelf registration statement, we established an at-the-market (ATM) equity sales program, including a forward sale component. On January 7, 2015, we entered into separate ATM Equity Offering Sales Agreements (Sales Agreements) with Merrill Lynch, Pierce, Fenner & Smith Incorporated (Merrill) and J.P. Morgan Securities LLC (JP Morgan), in their capacity as agents and/or as principals (Agents). Under the terms of the Sales Agreements, we may issue and sell, through either of the Agents, shares of our common stock, up to an aggregate sales price of $170 million (subject to certain exceptions) during the period beginning January 7, 2015 and ending October 31, 2016.

In addition to the issuance and sale of shares by us through the Agents, we may also enter into FSAs with affiliates of the Agents as Forward Purchasers. In connection with each FSA, the Forward Purchasers will, at our request, borrow from third parties and, through the Agents, sell a number of shares of our common stock equal to the number of shares underlying the FSA as its hedge. We expect to enter into separate FSAs each fiscal quarter during the term of the Sales Agreements and have done so in our second, third and fourth quarters of 2015.

Under the Sales Agreements, we specify the maximum number of our shares to be sold and the minimum price per share. We will pay each Agent (or, in the case of a FSA, the Forward Purchaser through a reduced initial forward sale price) a commission of 1.5% of the sales price of all shares sold through it as sales agent under the applicable Sales Agreement. The shares offered under the Sales Agreements may be offered, issued and sold in ATM sales through the Agents or offered in connection with one or more FSAs.

Under a FSA that we executed with Merrill on March 10, 2015, 612,000 shares were borrowed from third parties and sold by Merrill, from March 10, 2015 to April 24, 2015, at a weighted average share price of $36.83, net of adjustments. Based on the weighted average share price at the end of the trading period, the initial forward price was $36.28.

Under a FSA that we executed with JP Morgan on June 8, 2015, 795,529 shares were borrowed from third parties and sold by JP Morgan, from June 10, 2015 to July 30, 2015, at a weighted average share price of $36.42, net of adjustments. Based on the weighted average share price at the end of the trading period, the initial forward price was $35.87.

Under a FSA that we executed with Merrill on September 8, 2015, 114,500 shares were borrowed from third parties and sold by Merrill, from September 9, 2015 to September 15, 2015, at a weighted average share price of $36.58, net of adjustments. Based on the weighted average share price at the end of the trading period, the initial forward price was $36.03.

Under the terms of these FSAs, at our election, we could physically settle in shares, cash or net settle for all or a portion of our obligation under the agreements any time prior to December 15, 2015.

On October 29, 2015, we issued 1.5 million shares of our common stock to the forward counterparties by physically settling all of the FSAs entered into during 2015 and received net proceeds of $54.1 million. We recorded this amount in "Stockholders' equity" as an addition to "Common stock" in the Consolidated Balance Sheets. Upon settlement, we used the net proceeds from these FSA transactions to finance capital expenditures, repay outstanding short-term, unsecured notes under our CP program and for general corporate purposes.

On January 29, 2013, we entered into an underwriting agreement under our open combined debt and equity shelf registration statement to sell up to 4.6 million shares of our common stock of which 3 million direct shares were issued and settled on February 4, 2013 with proceeds of $92.6 million received. The shares were purchased by the underwriters at the net price of $30.88 per share, the offering price to the public of $32 per share per the prospectus less an underwriting discount of $1.12 per share.

The remaining 1.6 million shares under this same underwriting agreement were under FSAs with 1 million shares borrowed by a forward counterparty and sold to the underwriters for resale to the public on February 4, 2013 at the same price as the direct shares; the remaining .6 million shares were subject to a 30-day option by the underwriters to purchase these additional shares at the same price as the direct shares and would be, at our option, either issued at the time of purchase and delivered directly to the underwriters or borrowed and delivered to the underwriters by the forward counterparty. On February 19, 2013, the underwriters exercised their option to purchase the full additional .6 million shares of our common stock where the shares were borrowed from third parties and sold to the underwriters by the forward counterparty. Both of the FSAs had to be settled no later than mid-December 2013. Under the terms of these FSAs, at our election, we could physically settle in shares, cash or net share settle for all or a portion of our obligation under the agreements.

On December 16, 2013, we physically settled the FSAs by issuing 1.6 million shares of our common stock to the forward counterparty and received net proceeds of $47.3 million based on the net settlement price of $30.88 per share, the

Net benefit activities of equity method investments	**(58)**	(40)	Income from equity method investments
Income tax expense	**23**	16	Income taxes
Net benefit activities	**(35)**	(24)	
Total reclassification for the period, net of tax	**$ 983**	$ (308)	

(1) Amounts in parentheses indicate debits to accumulated OCIL.

8. Financial Instruments and Related Fair Value

Derivative Assets and Liabilities under Master Netting Arrangements

We maintain brokerage accounts to facilitate transactions that support our gas cost hedging plans. The accounting guidance related to derivatives and hedging requires that we use a gross presentation, based on our election, for the fair value amounts of our derivative instruments. We use long position gas purchase options to provide some level of protection for our customers in the event of significant commodity price increases. As of October 31, 2015 and 2014, we had long gas purchase options providing total coverage of 34.7 million dekatherms and 29.2 million dekatherms, respectively. The long gas purchase options held at October 31, 2015 are for the period from December 2015 through October 2016.

Fair Value Measurements

We use financial instruments that are not designated as hedges for accounting purposes to mitigate commodity price risk for our customers. We also have marketable securities that are held in rabbi trusts established for certain deferred compensation plans. In developing our fair value measurements of these financial instruments, we utilize market data or assumptions about risk and the risks inherent in the inputs to the valuation technique. 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. We classify fair value balances based on the observance of those inputs into the fair value hierarchy levels as set forth in the fair value accounting guidance and fully described in "Fair Value Measurements" in Note 1 to the consolidated financial statements.

The following table sets forth, by level of the fair value hierarchy, our financial assets that were accounted for at fair value on a recurring basis as of October 31, 2015 and 2014. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their consideration within the fair value hierarchy levels. We have had no transfers between any level during the years ended October 31, 2015 and 2014. We present our derivative positions at fair value on a gross basis and have only asset positions for all periods presented for the fair value of purchased call options held for our utility operations. There are no derivative contracts in a liability position, and we have posted no cash collateral nor received any cash collateral under our master netting arrangements. Therefore, we have no offsetting disclosures for financial assets or liabilities for our derivatives held for utility operations. Our derivatives held for utility operations are held with one broker as our counterparty.

Recurring Fair Value Measurements as of October 31, 2015

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Effects of Netting and Cash Collateral Receivables/ Payables	Total Carrying Value
Assets:					
Derivatives held for distribution operations	$ 1,343	$ —	$ —	$ —	$ 1,343
Debt and equity securities held as trading securities:					
Money markets	516	—	—	—	516
Mutual funds	4,386	—	—	—	4,386
Total fair value assets	$ 6,245	$ —	$ —	$ —	$ 6,245

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. Costs arising from the gas supply commodity and capacity commitments, while significant, are pass-through costs to our customers and are generally fully recoverable through our PGA procedures and prudence reviews in North Carolina and South Carolina and under the TIP in Tennessee. The time periods for fixed payments under pipeline and storage capacity contracts are up to twenty years. The time periods for fixed payments under gas supply contracts are up to two years. The time period for the gas supply purchase commitments is up to fifteen 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 are up to five years. Other purchase obligations consist primarily of commitments for pipeline products, equipment and contractors.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the 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 Comprehensive Income as part of gas purchases and included in "Cost of Gas."

As of October 31, 2015, future unconditional purchase obligations for the next five years ending October 31 and thereafter are as follows.

In thousands	Pipeline and Storage Capacity	Gas Supply Reservation Fees	Gas Supply Purchase Commitments	Telecommunications and Information Technology	Other	Total
2016	$ 178,594	$ 4,577	$ 65,286	$ 6,164	$ 45,577	$ 300,198
2017	163,806	165	89,784	1,639	—	255,394
2018	143,728	—	69,569	669	—	213,966
2019	132,259	—	69,569	610	—	202,438
2020	114,400	—	69,759	—	—	184,159
Thereafter	516,333	—	707,698	—	—	1,224,031
Total	$ 1,249,120	$ 4,742	$ 1,071,665	$ 9,082	$ 45,577	$2,380,186

Legal

We have only routine litigation in the normal course of business. We do not expect any of these routine litigation matters to have a material effect, either individually or in the aggregate, on our financial position, results of operations or cash flows.

Letters of Credit

We use letters of credit to guarantee claims from self-insurance under our general and automobile liability policies. We had $1.6 million in letters of credit that were issued and outstanding at October 31, 2015. Additional information concerning letters of credit is included in Note 6 to the consolidated financial statements.

Surety Bonds

In the normal course of business, we are occasionally required to provide financial commitments in the form of surety bonds to third parties as a guarantee of our performance on commercial obligations. We have agreements that indemnify certain issuers of surety bonds against losses that they may incur as a result of executing surety bonds on our behalf. If we were to fail to perform according to the terms of the underlying contract, any draws upon surety bonds issued on our behalf would then trigger our payment obligation to the surety bond issuer. As of October 31, 2015, we had open surety bonds with a total contingent obligation of $6.6 million.

Environmental Matters

Our three regulatory commissions have authorized us to utilize deferral accounting in connection with costs for environmental assessments and cleanups. Accordingly, we have established regulatory assets for actual environmental costs incurred and have recorded estimated environmental liabilities, including those for our manufactured gas plant (MGP) sites, LNG facilities and underground storage tanks (USTs).

In 1997, we entered into a settlement with a third-party with respect to nine MGP sites that we have owned, leased or operated 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.

In connection with our 2003 North Carolina Natural Gas Corporation (NCNG) acquisition, several MGP sites owned by NCNG were transferred to a wholly-owned subsidiary of Progress Energy, Inc. (Progress), now a subsidiary of Duke Energy, 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.

As of October 31, 2015, our estimated undiscounted environmental liability totaled $1.2 million, and consisted of $1.1 million for MGP sites for which we retain responsibility and $.1 million for the Huntersville LNG facility. The costs we reasonable expect to incur are estimated using assumptions based on actual costs incurred, the timing of future payments and inflation factors, among others. We have incurred $2.2 million of remediation costs related to our MGP sites and $4.8 million related to our Huntersville LNG facility.

We continue to expand our sampling of our pipelines for coatings containing asbestos. Additionally, we continue to educate our employees on the hazards of asbestos and implemented procedures for removing these coatings from our pipelines when we must excavate and expose portions of the pipeline.

As of October 31, 2015, our regulatory assets for unamortized environmental costs in our three-state territory totaled $6.6 million. We received approval from the TRA to recover $2 million of our deferred Tennessee environmental costs over an eight-year period beginning March 2012, pursuant to the 2012 general rate case proceeding in Tennessee. We will seek recovery of the remaining Tennessee balance in future rate proceedings. The approval by the NCUC in December 2013 of the settlement of the general rate proceeding allowed recovery of $6.3 million of our deferred North Carolina environmental costs over a five-year period beginning January 2014. We received approval from the PSCSC to recover $.1 million of our deferred South Carolina environmental costs over a one-year period beginning November 2014, pursuant to the annual rate stabilization order issued in October 2014.

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

10. Employee Benefit Plans

Under accounting guidance, we are required to recognize all obligations related to defined benefit pension and other postretirement employee benefits (OPEB) plans and quantify the plans' funded status as an asset or liability on the Consolidated Balance Sheets. In accordance with accounting guidance, we measure the plans' assets and obligations that determine our funded status as of the end of our fiscal year, October 31. We are required to recognize as a component of OCI the changes in the funded status that occurred during the year that are not recognized as part of net periodic benefit cost; however, in 2006, we obtained regulatory treatment from the NCUC, the PSCSC and the TRA to record the amount that would have been recorded in accumulated OCI as a regulatory asset or liability as the future recovery of pension and OPEB costs is probable. To date, our regulators have allowed future recovery of our pension and OPEB costs. For the impact of this regulatory treatment, see the following table of actuarial plan information that specifies the amounts not yet recognized as a component of cost and recognized as a regulatory asset or liability. Our plans' assets are required to be accounted for at fair value.

Pension Benefits

We have a noncontributory, tax-qualified defined benefit pension plan (qualified pension plan) for our eligible employees. A defined benefit plan specifies the amount of benefit that an eligible participant eventually will receive upon retirement using information about that participant. 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. The qualified pension plan is closed to employees hired after December 31, 2007. Employees hired prior to January 1, 2008 continue to participate in the qualified pension plan. Employees are vested after five years of service and can be credited with up to a total of 35 years of service. When a vested employee leaves the company, his benefit payment will be calculated as the greater of the accrued benefit as of December 31, 2007 under a specific formula plus the accrued benefit calculated under a second formula for years of service after December 31, 2007, or the benefit for all years of service up to 35 years under the second formula.

The investment objectives of the qualified pension plan are oriented to meet both the current ongoing and future commitments to the participants and designed to grow at an acceptable rate of return for the risks permitted under the investment policy guidelines. Assets are structured to provide for both short-term and long-term needs and to meet the objectives of the qualified pension plan as specified by the Benefits Committee of the Board of Directors.

Our primary investment objective of the qualified pension plan is to generate sufficient assets to meet plan liabilities. The plan's assets will therefore be invested to maximize long-term returns in a manner that is consistent with the plan's liabilities, cash flow requirements and risk tolerance. The plan's liabilities are defined in terms of participant salaries. Given the nature of these liabilities and recognizing the long-term benefits of investing in return-generating assets, the qualified pension plan seeks to invest in a diversified portfolio to:

- Achieve full funding over the longer term, and
- Control year-to-year fluctuations in pension expense that is created by asset and liability volatility.

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 investment philosophy of the qualified pension plan is to maintain a balanced portfolio which is diversified across asset classes. The portfolio is primarily composed of equity and fixed income investments in order to provide diversification as to issuers, economic sectors, markets and investment instruments. Risk and quality are viewed in the context of the diversification requirements of the aggregate portfolio. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The qualified pension plan maintains the following types of investments:

- Fixed income securities: includes U.S. treasuries, corporate bonds, high yield debt (bank loans), asset-backed securities and derivatives. The derivatives in the fixed income portfolio are fully collateralized. The investment guidelines limit liabilities created with derivatives in the fixed income portfolio to cash equivalents plus 10% of the portfolio's market value. The aggregate risk exposure of the plan can be no greater than that which could be achieved without using derivatives.
- Equity securities: includes large cap growth, large cap value and small cap domestic equity securities, as well as international equity.
- Real estate: includes a diversified global real estate investment trust fund.
- Other investments: includes commodities, hedge funds and private equity funds that follow several diversified strategies.

The target and actual allocations of the qualified pension plan's assets are as follows:

Asset Allocations	Target Allocation	Assets at October 31 2015	2014
Fixed income securities	45%	**46%**	45%
Equity securities	35%	**34%**	31%
Real estate	5%	**5%**	5%
Cash and cash equivalents	—%	**1%**	8%
Other investments	15%	**14%**	11%
Total	100%	**100%**	100%

Employees hired or rehired after December 31, 2007 cannot participate in the qualified pension plan but are participants in the Money Purchase Pension (MPP) plan, a defined contribution pension plan that allows the employee to direct the investments and assume the risk of investment returns. A defined contribution plan specifies the amount of the employer's annual contribution to individual participant accounts established for the retirement benefit. Eligible employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Under the MPP plan, we annually deposit a percentage of each participant's pay into an account of the MPP plan. This contribution equals 4% of the participant's compensation plus an additional 4% of compensation above the social security wage base up to the Internal Revenue Service (IRS) compensation limit. The participant is vested in this plan after three years of service. During the year ended October 31, 2015, 2014 and 2013 we contributed $1.4 million, $.9 million and $.7 million, respectively, to the MPP plan.

OPEB Plan

We provide certain postretirement health care and life insurance benefits to eligible retirees. The liability associated with such benefits is funded in irrevocable trust funds that can only be used to pay the benefits. Employees are first eligible to retire and receive these benefits at age 55 with ten or more years of service after the age of 45. Employees who met this requirement in 1993 or who retired prior to 1993 are in a "grandfathered" group for whom we pay the full cost of the retiree's coverage. Retirees not in the grandfathered group have a portion 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. Employees hired after January 1, 2008 have to complete ten years of service after age 50 to be eligible for benefits, and no benefits are provided to those employees after age 65 when they are automatically eligible for Medicare benefits to cover health costs. Our OPEB plan includes a defined dollar benefit to pay the premiums for Medicare Part D. Employees who meet the eligibility requirements to retire also receive a life insurance benefit of $15,000.

In September 2015, we announced the replacement of the existing retiree medical and dental group coverage for eligible retirees with a tax-free Health Reimbursement Arrangement (HRA), effective January 1, 2016. Under the new HRA, participating eligible retirees and their dependents will receive a subsidy each year through the HRA account to help purchase medical and dental coverage available on public and private health care exchanges using a tax-advantaged account funded by us to pay for allowable medical expenses. The impact of the amendment was not material to us.

OPEB plan assets are comprised of mutual funds within a 401(h) and Voluntary Employees' Beneficiary Association trusts. The investment philosophy is similar to the qualified pension plan as discussed above, except the OPEB fixed income portfolio does not include derivatives. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The target and actual allocations of the OPEB plan's assets are as follows:

Asset Allocations	Target Allocation	Assets at October 31 2015	2014
Fixed income securities	45% (1)	**47%**	44%
Equity securities	47%	**44%**	42%
Real estate	5%	**5%**	5%
Cash and cash equivalents	3%	**4%**	9%
Total	100%	**100%**	100%

(1) Includes 5% target allocation to high yield fixed income.

Supplemental Executive Retirement Plans

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

We have a non-qualified defined contribution restoration plan (DCR plan) for certain officers at the vice president level and above where benefits payable under the plan are informally funded annually through a rabbi trust with a bank as the trustee. We contribute 13% of the total cash compensation (base salary, short-term incentive and MVP incentive) that exceeds the IRS compensation limit to the DCR plan account of each covered executive. Participants may not contribute to the DCR plan. Vesting under the DCR plan is five-year cliff vesting of annual contributions. Participants in the DCR plan may provide instructions to us for the deemed investment of their plan accounts. Distribution will occur upon separation of service or death of the participant.

We have a voluntary deferred compensation plan for the benefit of all director-level employees and officers, where we make no contributions to this plan. Benefits under this plan, known as the Voluntary Deferral Plan (VDP), are also informally funded monthly through a rabbi trust with a bank as the trustee. Participants may defer up to 50% of base salary with elections made by December 31 prior to the upcoming calendar year, and up to 95% of annual incentive pay with elections made by April 30. Vesting is immediate and deferrals are held in the rabbi trust. Participants may provide instructions to us for the deemed investment of their plan accounts. Distributions can be made from the VDP on a specified date that is at least two years from the date of deferral, a change in control, on separation of service or upon death.

Our funding to the DCR plan account for the years ended October 31, 2015 and 2014, and the amounts recorded as liabilities for these two deferred compensation plans as of October 31, 2015 and 2014, are presented below.

In thousands	2015	2014
Funding	**$ 548**	$ 524
Liability:		
Current	**236**	214
Noncurrent	**5,089**	4,248

We provide term life insurance policies for certain officers at the vice president level and above who were former participants in a terminated SERP; the level of the insurance benefit is dependent upon the level of the benefit provided under the terminated SERP. These life insurance policies are owned exclusively by each officer. Premiums on these policies are paid and expensed. We also provide a term life insurance benefit equal to $200,000 to all officers and director-level employees for which we bear the cost of the policies. The cost of these premiums is presented below.

In thousands	2015	2014	2013
Term life policies of certain officers at the vice president level and above	**$ 35**	$ 30	$ 27

Officers and director-level employees	**30**	32	28

Actuarial Plan Information

A reconciliation of changes in the plans' benefit obligations and fair value of assets for the years ended October 31, 2015 and 2014, a statement of the funded status and the amounts reflected in the Consolidated Balance Sheets for the years ended October 31, 2015 and 2014, and the weighted average assumptions used in the measurement of the benefit obligations as of October 31, 2015 and 2014 are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
In thousands	**2015**	2014	**2015**	2014	**2015**	2014
Accumulated benefit obligation at year end	**$ 263,120**	$ 252,706	**$ 5,527**	$ 5,925	**N/A**	N/A
Change in projected benefit obligation:						
Obligation at beginning of year	**$ 302,686**	$ 272,403	**$ 5,925**	$ 4,736	**$ 37,817**	$ 33,678
Service cost	**11,403**	10,865	**—**	—	**1,182**	1,109
Interest cost	**12,018**	11,781	**209**	200	**1,475**	1,448
Plan amendments	**—**	—	**—**	485	**(1,877)**	—
Actuarial (gain) loss	**3,524**	23,646	**(100)**	956	**1,697**	3,734
Participant contributions	**—**	—	**—**	—	**611**	805
Administrative expenses	**(590)**	(465)	**—**	—	**—**	—
Benefit payments	**(17,504)**	(15,544)	**(507)**	(452)	**(3,348)**	(2,957)
Obligation at end of year	**311,537**	302,686	**5,527**	5,925	**37,557**	37,817
Change in fair value of plan assets:						
Fair value at beginning of year	**336,443**	300,661	**—**	—	**27,747**	25,961
Actual return on plan assets	**958**	31,791	**—**	—	**315**	1,874
Employer contributions	**10,000**	20,000	**507**	452	**2,221**	2,064
Participant contributions	**—**	—	**—**	—	**611**	805
Administrative expenses	**(590)**	(465)	**—**	—	**—**	—
Benefit payments	**(17,504)**	(15,544)	**(507)**	(452)	**(3,348)**	(2,957)
Fair value at end of year	**329,307**	336,443	**—**	—	**27,546**	27,747
Funded status at year end - over (under)	**$ 17,770**	$ 33,757	**$ (5,527)**	$ (5,925)	**$ (10,011)**	$ (10,070)
Noncurrent assets	**$ 17,770**	$ 33,757	**$ —**	$ —	**$ —**	$ —
Current liabilities	**—**	—	**(520)**	(521)	**—**	—
Noncurrent liabilities	**—**	—	**(5,007)**	(5,404)	**(10,011)**	(10,070)
Net amount recognized	**$ 17,770**	$ 33,757	**$ (5,527)**	$ (5,925)	**$ (10,011)**	$ (10,070)
Amounts Not Yet Recognized as a Component of Cost and Recognized in a Deferred Regulatory Account:						
Unrecognized prior service credit (cost)	**$ 12,848**	$ 15,046	**$ (208)**	$ (439)	**$ 1,877**	$ —
Unrecognized actuarial loss	**(120,541)**	(103,038)	**(1,560)**	(1,745)	**(7,185)**	(3,995)
Regulatory asset	**(107,693)**	(87,992)	**(1,768)**	(2,184)	**(5,308)**	(3,995)
Cumulative employer contributions in excess of cost	**125,463**	121,749	**(3,759)**	(3,741)	**(4,703)**	(6,075)
Net amount recognized	**$ 17,770**	$ 33,757	**$ (5,527)**	$ (5,925)	**$ (10,011)**	$ (10,070)

Weighted average assumptions used in the measurement of						
the benefit obligations:						
Discount rate	**4.34%**	4.13%	**3.85%**	3.69%	**4.38%**	4.03%
Rate of compensation increase	**4.07%**	3.68%	**N/A**	N/A	**N/A**	N/A

In 2006 with the implementation of accounting guidance for employers' accounting for defined benefit pension and other postretirement plans, the NCUC, the PSCSC and the TRA approved our request to place certain defined benefit postretirement obligations in a deferred regulatory account as presented above instead of OCIL. The regulators have allowed future recovery of our pension and OPEB costs to this date.

Net periodic benefit cost components for the years ended October 31, 2015, 2014 and 2013 and the weighted average assumptions used to determine net period benefit cost as of October 31, 2015, 2014 and 2013 are presented below.

	Qualified Pension			Nonqualified Pension			Other Benefits		
In thousands	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Service cost	**$ 11,403**	$ 10,865	$ 12,005	**$ —**	$ —	$ —	**$ 1,182**	$ 1,109	$ 1,327
Interest cost	**12,018**	11,781	9,946	**209**	200	157	**1,475**	1,448	1,130
Expected return on plan assets	**(23,614)**	(22,530)	(21,105)	**—**	—	—	**(1,837)**	(1,782)	(1,663)
Amortization of transition obligation	**—**	—	—	**—**	—	—	**—**	—	667
Amortization of prior service cost (credit)	**(2,198)**	(2,198)	(2,198)	**231**	243	81	**—**	—	—
Amortization of net loss	**8,676**	7,685	11,202	**85**	31	161	**29**	—	—
Net periodic benefit cost	**6,285**	5,603	9,850	**525**	474	399	**849**	775	1,461
Other changes in plan assets and benefit obligation recognized through regulatory asset or liability:									
Prior service cost (credit)	**—**	—	—	**—**	485	—	**(1,877)**	—	—
Net loss (gain)	**26,179**	14,385	(30,094)	**(100)**	956	(540)	**3,219**	3,641	(2,278)
Amounts recognized as a component of net periodic benefit cost:									
Transition obligation	**—**	—	—	**—**	—	—	**—**	—	(667)
Amortization of net loss	**(8,676)**	(7,685)	(11,202)	**(85)**	(31)	(161)	**(29)**	—	—
Prior service (cost) credit	**2,198**	2,198	2,198	**(231)**	(243)	(81)	**—**	—	—
Total recognized in regulatory asset (liability)	**19,701**	8,898	(39,098)	**(416)**	1,167	(782)	**1,313**	3,641	(2,945)
Total recognized in net periodic benefit and regulatory asset (liability)	**$ 25,986**	$ 14,501	$(29,248)	**$ 109**	$ 1,641	$ (383)	**$ 2,162**	$ 4,416	$ (1,484)
Weighted average assumptions used to determine the net periodic benefit cost:									
Discount rate	**4.13%**	4.55%	3.51%	**3.69%**	3.98%	2.95%	**4.03%**	4.44%	3.34%
Expected long-term rate of return on plan assets	**7.50%**	7.75%	8.00%	**N/A**	N/A	N/A	**7.50%**	7.75%	8.00%
Rate of compensation increase	**3.68%**	3.72%	3.76%	**N/A**	N/A	N/A	**N/A**	N/A	N/A

The 2016 estimated amortization of the following items for our plans, which are recorded as a regulatory asset or liability instead of accumulated OCIL discussed above, are as follows.

In thousands	Qualified Pension	Nonqualified Pension	Other Benefits
Amortization of unrecognized prior service (credit) cost	$ (2,198)	$ 208	$ (332)
Amortization of unrecognized actuarial loss	8,164	81	459

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 non-callable bonds rated AA or better by either Moody's Investors Service's or Standard & Poor's Ratings Services that have a yield higher than the regression mean yield curve. The discount rate can vary from plan year to plan year. As of October 31, 2015, the benchmark by plan was as follows.

Qualified pension plan	4.34%
NCNG SERP	3.78%
Directors' SERP	3.91%
Piedmont SERP	3.17%
OPEB	4.38%

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, meaning that 20% of the prior five years' asset gains and losses are recognized each year. This method has been applied consistently in all years presented in the consolidated financial statements.

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 amortization period used for the purposes mentioned above for the NCNG SERP and the Piedmont SERP is an expected future lifetime as there are no active members in these plans. The method of amortization in all cases is straight-line.

In addition to the assumptions in the above table, we also use subjective factors such as withdrawal and mortality rates in determining benefit obligations for all of our benefit plans. Our assumed mortality rates incorporate the new set of mortality tables issued by the Society of Actuaries in October 2014. We also applied the updated projection scale issued by the Society of Actuaries in October 2015.

We anticipate that we will contribute the following amounts to our plans in 2016.

In thousands	
Qualified pension plan *	$ 10,000
Nonqualified pension plans	520
MPP plan	1,650
OPEB plan	1,300

* Funded in November 2015.

The Pension Protection Act of 2006 (PPA) specified funding requirements for single employer defined benefit pension plans. We are in compliance with the 100% funding target established in the PPA.

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

In thousands	Qualified Pension	Nonqualified Pension	Other Benefits
2016	$ 28,147	$ 520	$ 1,987
2017	19,911	504	2,145
2018	20,413	482	2,301
2019	21,348	510	2,421
2020	21,829	491	2,494
2021 - 2025	114,267	2,100	13,379

Based on the retiree medical and dental group coverage changing to a HRA where the retiree subsidy provided by Piedmont is fixed and assumed to not increase, we are no longer impacted by the health care cost component (projected health care cost trend rates) for our accumulated postretirement benefit obligation as of October 31, 2015.

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, 2014 is presented below.

	2014
Health care cost trend rate assumed for next year	7.40%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%
Year that the rate reaches the ultimate trend rate	2027

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

In thousands	1% Increase	1% Decrease

Effect on total of service and interest cost components of net periodic postretirement health care benefit cost for the year ended October 31, 2015	$ 34	$ (35)

Beginning in 2016, we will change the method we use to estimate the service and interest cost components of net periodic benefit costs for our plans from using a developed zero-coupon spot rate yield curve as discussed above. We have elected to use a full yield curve approach in the estimation of these components of benefit costs by applying the specific spot rates along the yield curve used in the determination of the benefit obligations to the relevant projected cash flows. We will make this change to improve the correlation between projected benefit cash flows and the corresponding yield curve spot rates and to provide a more precise measurement of service and interest costs. This change will not affect the measurement of our total benefit obligations as the change in the service and interest costs is completely offset by the actuarial (gain) loss reported. We will account for this change as a change in estimate and, accordingly, will account for it prospectively beginning in 2016.

Fair Value Measurements

Following is a description of the valuation methodologies used for assets measured at fair value in our qualified pension plan.

Cash and cash equivalents – These are Level 1 assets valued at face value as they are primarily cash or cash equivalents. The assets that are Level 2 assets are valued at the market value of the shares held by the plan at the valuation date for a money market mutual fund.

Fixed income securities – These assets include:

- U.S. treasuries – These are Level 2 assets whose values are based on observable market information including quotes from a quotation reporting system, established market makers or pricing services. This asset class includes long duration fixed income investments.
- Corporate bonds, collateralized mortgage obligations, municipals – These are Level 2 assets valued based on primarily observable market information or broker quotes on a non-active market. This class includes long duration fixed income investments.
- Derivatives – The Level 1 assets are valued using a compilation of observable market information on an active market. The Level 2 assets are valued using broker quotes on a non-active market.

Equity securities – These are level 1 assets valued at the market price of the active market on which the individual security is traded.

Mutual funds – These are Level 1 assets valued at the publicly quoted NAV per share computed as of the close of business on our balance sheet date. Mutual funds with a NAV per share that is not publicly available are classified as Level 2.

Common trust fund – These are Level 2 assets held in a common trust fund in which we own interests that are valued at the NAV of the funds as traded on international exchanges. Currently, there are no restrictions on redemptions for the fund.

Private equity fund of funds – This is a Level 3 asset invested in hedge fund of funds valued based on a quarterly compilation of the financial statements from the underlying partnerships in which the fund invests. There are currently redemption restrictions for this fund. The target allocation for this investment is 3.5% but is still being funded through capital calls; $4 million of the original $12 million subscription remains unfunded. Until a 3.5% allocation can be achieved, the balance of the 3.5% allocation is invested in a low-cost equity index fund that tracks the Standard & Poor's 500 Stock Index. Our investment is in various funds that invests in North American companies, allocate capital to private equity funds, invest in venture capital partnerships and private equity partnerships in emerging markets.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Hedge fund of funds – These investments are across a variety of markets through investment funds or managed accounts that invest in equities, equity-related instruments, fixed income and other debt-related instruments. Currently, there are no restrictions on redemptions for the fund.

Commodities fund of funds – Currently, there are no restrictions on redemptions for the fund. These investments are in commodities fund of funds that are actively managed through a well-diversified group of underlying managers.

High yield debt (bank loans) – These assets are held in a common trust fund that invest in global bank loans. Currently, there are no restrictions on redemption for the fund.

As stated above, some of our investments for the qualified pension plan have redemption limitations, restrictions and notice requirements which are further explained below.

Investment	Redemption Frequency	Other Redemption Restrictions	Redemptions Notice Period
Common trust fund - International growth	Monthly	None	30 days
Hedge fund of funds	Quarterly	Redeemed in whole or part but not less than the minimum redemption amount for each currency. Redemption within one year of purchase is subject to 1.5% redemption fee. Redeemed on "first in first out" basis. None of our investment is subject to the redemption fee. Fund's Board of Directors may limit or suspend share redemptions until a further notification ending suspension. No such notification has been received as of October 31, 2015.	65 days
Private equity fund of funds	Limited	Investors have only very limited withdrawal rights for specific legal or regulatory reasons. Any transfer of interest will be subject to approval.	(1)
Commodities fund of funds	Monthly	Redemption within one year of purchase is subject to 1% redemption fee. None of our investment is subject to the redemption fee. If 95% or more of the balance is requested, 95% of the balance will be paid within 30 days. Any outstanding balance or interest owed will be paid after the annual audit is complete.	35 days
Bank loans	Daily	None	30 days

(1) The investment cannot be redeemed. We receive distributions only through the liquidation of the underlying assets. The assets are expected to be liquidated over the next 10 to 12 years.

The qualified pension plan's asset allocations by level within the fair value hierarchy as of October 31, 2015 and 2014 are presented below. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and their consideration within the fair value hierarchy levels. For further information on a description of the fair value hierarchy, see "Fair Value Measurements" in Note 1 to the consolidated financial statements.

	Qualified Pension Plan as of October 31, 2015			
In thousands	Quoted Prices In Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents	$ 2,782	$ 89	$ —	$ 2,871
Fixed income securities	—	84,135	—	84,135
Equity securities	44,738	—	—	44,738
Mutual funds	78,853	42,890	—	121,743
Common trust fund	—	23,571	—	23,571

Private equity fund of funds	—	—	8,344	8,344
Other Investments:				
Hedge fund of funds				19,809 (1)
Commodities fund of funds				7,688 (1)
High yield debt (bank loans)				16,408 (1)
Total assets at fair value	$ 126,373	$ 150,685	$ 8,344	$ 329,307

In thousands	Qualified Pension Plan as of October 31, 2014 Quoted Prices In Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents	$ 27,932	$ 435	$ —	$ 28,367
Fixed income securities	48	78,026	—	78,074
Equity securities	51,266	—	—	51,266
Mutual funds	54,502	48,049	—	102,551
Common trust fund	—	22,877	—	22,877
Private equity fund of funds	—	—	7,158	7,158
Other Investments:				
Hedge fund of funds				19,829 (1)
Commodities fund of funds				10,134 (1)
High yield debt (bank loans)				16,187 (1)
Total assets at fair value	$ 133,748	$ 149,387	$ 7,158	$ 336,443

(1) In accordance with accounting guidance, certain investments that are measured at fair value using the NAV per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets above.

The following is a reconciliation of the assets in the qualified pension plan that are classified as Level 3 in the fair value hierarchy.

In thousands	Private Equity Fund of Funds
Balance, October 31, 2013	$ 4,659
Actual return on plan assets:	
Relating to assets still held at the reporting date	1,031
Relating to assets sold during the period	113
Purchases, sales and settlements (net)	1,355
Transfer in/out of Level 3	—
Balance, October 31, 2014	7,158
Actual return on plan assets:	
Relating to assets still held at the reporting date	**413**
Relating to assets sold during the period	**618**
Purchases, sales and settlements (net)	**155**
Transfer in/out of Level 3	—
Balance, October 31, 2015	**$ 8,344**

During the year, the qualified pension plan raises cash from various plan assets in order to fund periodic and lump sum benefit payments. Cash is raised as needed primarily from investments that have exceeded their target allocation and is dependent upon the number of retirees seeking lump sum distributions.

There are significant unobservable inputs used in the fair value measurements of our investment in the private equity fund of funds' limited partnerships. We are subject to the business risks inherent in the markets in which the partnerships are invested. The success or failure of the underlying businesses of the various partnerships that have been funded would result in a higher or lower fair value measurement.

Following is a description of the valuation methodologies used for assets measured at fair value in our OPEB plan.

Cash and cash equivalents – These are Level 1 assets having maturities of three months or less when purchased and are considered to be cash equivalents.

Mutual funds – These are Level 1 assets valued at the publicly quoted NAV per share computed as of the close of business on our balance sheet date.

The OPEB plan's asset allocations by level within the fair value hierarchy as of October 31, 2015 and 2014 are presented below. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and their placement within the fair value hierarchy levels. For further information on a description of the fair value hierarchy, see "Fair Value Measurements" in Note 1 to the consolidated financial statements.

	Other Benefits as of October 31, 2015			
In thousands	Quoted Prices In Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents	**$ 1,164**	**$ —**	**$ —**	**$ 1,164**
Mutual funds	**26,382**	**—**	**—**	**26,382**
Total assets at fair value	**$ 27,546**	**$ —**	**$ —**	**$ 27,546**

	Other Benefits as of October 31, 2014			
In thousands	Quoted Prices In Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents	$ 2,590	$ —	$ —	$ 2,590
Mutual funds	25,157	—	—	25,157
Total assets at fair value	$ 27,747	$ —	$ —	$ 27,747

401(k) Plan

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

Employees receive a company match of 100% up to the first 5% of eligible pay contributed. Employees may contribute up to 50% of eligible pay to the 401(k) on a pre-tax basis, up to the Tax Code annual contribution and compensation limits. We automatically enroll all eligible non-participating employees in the 401(k) plan at a 2% contribution rate unless the employee chooses not to participate by notifying our record keeper. For employees who are automatically enrolled in the 401(k) plan, we automatically increase their contributions by 1% each year to a maximum of 5% unless the employee chooses to opt out of the automatic increase by contacting our record keeper. If the employee does not make an investment election, employee contributions and matches are automatically invested in a diversified portfolio of stocks and bonds. Participants may direct up to 20% of their contributions and company matching contributions as an investment in the Piedmont Stock Fund. Employees may change their contribution rate and investments at any time. For the years ended October 31, 2015, 2014 and 2013, we made matching contributions to participant accounts as follows.

In thousands	**2015**	2014	2013
401(k) matching contributions	**$ 6,584**	$ 6,134	$ 5,688

As a result of a plan merger effective in 2001, participants' accounts in our employee stock ownership plan (ESOP) were transferred into the participants' 401(k) accounts. 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.

11. Employee Share-Based Plans

Liability Plans

Under our shareholder approved ICP, eligible officers and other participants are awarded units that pay out depending upon the level of performance achieved by Piedmont during three-year incentive plan performance periods. Distribution of those awards may be made in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation. These plans require that a minimum threshold performance level be achieved in order for any award to be distributed. For the years ended October 31, 2015, 2014 and 2013, we recorded compensation expense, and as of October 31, 2015 and 2014, we accrued a liability 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 each quarter and at the settlement date.

We have granted three series of awards under the approved ICP, one with a three-year performance period that ended October 31, 2015 (2015 plan) and two other awards ending on October 31, 2016 (2016 plan) and October 31, 2017 (2017 plan). For each of these performance periods, awards are weighted and based on achievement relative to:

- a target annual compounded increase in basic EPS (37.5% weight),
- total shareholder returns compared to a group of peer companies that are domiciled in the United States, publicly traded in the U.S. energy industry with a primary focus on natural gas distribution and transmission businesses in multi-state territories and have similar annual revenues and market capitalization to ours (37.5% weight), and
- an actual average return on equity compared to the weighted average return on equity allowed by our regulatory commissions (25% weight).

In December 2010, a long-term retention stock unit award under the ICP (where a stock unit equals one share of our common stock upon vesting) was approved for eligible officers and other participants to support our succession planning and retention strategies. This retention stock unit award vested for participants who met the retention requirements at the end of the three-year period ending in December 2013 and settled in the same month with payment in the form of shares of our common stock and withholdings for payment of applicable taxes on the compensation.

Also under our approved ICP, 64,700 unvested retention stock units (RSUs) were granted to our President and Chief Executive Officer (CEO) in December 2011. During the five-year vesting period, any dividend equivalents will accrue on these stock units and be converted into additional units at the same rate and based on the closing price on the same payment date as dividends on our common stock. The RSUs will vest, payable in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation, over a five-year period only if he is an employee on each vesting date. In accordance with the vesting schedule, 20% of the units vested on December 15, 2014, 30% of the units vest on December 15, 2015 and 50% of the units vest on December 15, 2016. For the twelve months ended October 31, 2015, 2014 and 2013, we recorded compensation expense, and as of October 31, 2015 and 2014, we accrued a liability for this award based on the fair market value of our common stock at the end of each quarter. The liability is re-measured to market value each quarter and at the settlement date.

The December 15, 2014 vesting covered 20% of the grant, including accrued dividends, for a total of 14,461 shares of our common stock. After withholdings of $.3 million for federal and state income taxes, our President and CEO received 7,231 shares of our common stock at the NYSE composite closing price on December 12, 2014 of $37.89 per share.

The December 15, 2015 vesting covers 30% of the grant, including accrued dividends, for a total of 22,434 shares of our common stock. After withholdings of $.6 million for federal and state income taxes, our President and CEO received 11,732 shares of our common stock at the NYSE composite closing price on December 14, 2015 of $56.85 per share.

At the time of distribution of any award under the ICP, the number of shares of common stock issuable is reduced by the withholdings for payment of applicable income taxes for each participant. The participant may elect income tax withholdings at or above the minimum statutory withholding requirements. The maximum withholdings allowed is 50%. To date, shares withheld for payment of applicable income taxes have been immaterial. We present the net shares issued in the Consolidated Statements of Stockholders' Equity and in Note 7 to the consolidated financial statements.

The compensation expense related to the awards under the ICP for the years ended October 31, 2015, 2014 and

2013, and the amounts recorded as liabilities in "Other noncurrent liabilities" in "Noncurrent Liabilities" with the current portion recorded in "Other current liabilities" in "Current Liabilities" in the Consolidated Balance Sheets as of October 31, 2015 and 2014 are presented below.

In thousands	2015	2014	2013
Compensation expense	**$ 14,173**	$ 8,496	$ 4,526
Tax benefit	**3,966**	2,476	1,538
Liability	**22,037**	15,130	

Based on current accrual assumptions as of October 31, 2015, the expected payout for the approved incentive compensation awards at target will occur in the following fiscal years with the 2015 plan paying out in fiscal year 2016, the 2016 plan paying out in fiscal year 2017 and the 2017 plan paying out in fiscal year 2018. Payouts as currently accrued are presented net of estimated federal and state withholding payments.

In thousands	2016	2017	2018
Amount of payout	$ 10,866	$ 8,179	$ 2,992

The Merger Agreement provides for the conversion of the shares subject to the RSUs and ICP awards at the performance level specified in the Merger Agreement into the right to receive $60 cash per share upon the closing of the transactions contemplated in the Merger Agreement. In November and December 2015, the Compensation Committee of our Board of Directors authorized the accelerated vesting, payment and taxation of the RSUs for our President and CEO (accelerated RSUs) and the ICP awards under the 2016 plan and the 2017 plan (accelerated ICP awards) at the target level of performance to participants, at his and their elections to accelerate, in the form of restricted shares of our common stock, net of shares withheld for applicable taxes. The acceleration of the vesting and payment of these awards will mitigate the effects of Section 280G of the Tax Code, including increasing the deductibility of such payments for the Company. The acceleration and payout of the ICP awards, at a 96% election rate by the participants, and the RSUs, per the election of our President and CEO, occurred on December 15, 2015.

In connection with the election to accelerate the ICP awards and the RSUs, each respective participant executed a share repayment agreement dated December 15, 2015. Under the share repayment agreements, each participant agreed to repay to the Company the net after-tax shares of common stock issued to him/her in connection with the acceleration, as well as shares of common stock resulting from the reinvestment of dividends paid with respect to these shares of common stock that are required to be reinvested in additional shares of common stock, to the extent the shares of common stock would not otherwise have been earned or payable absent the acceleration. Under the share repayment agreements, the shares of common stock delivered to the participants, including dividends paid by the Company and reinvested as discussed above, may not be transferred or encumbered until such shares of common stock are no longer subject to repayment under the applicable repayment agreement. The restricted shares of common stock and dividends earned on those shares of common stock are subject to full or partial cancellation if the Acquisition is not consummated or the participant leaves the Company prior to consummation of the Acquisition. The participants otherwise have all rights of shareholders with respect to the restricted shares of common stock.

The accelerated ICP awards and the accelerated RSUs were priced at the NYSE composite closing price of $56.85 on December 14, 2015. Under the accelerated ICP awards, 162,390 restricted shares of our common stock were issued to participants, net of shares withheld for applicable federal and state income taxes. The gross value of the shares issued for the accelerated ICP awards was $17.4 million, or $9.2 million net of federal and state tax withholdings. Under the accelerated RSUs, 19,554 restricted shares of our common stock were issued to our President and CEO, net of shares withheld for applicable federal and state income taxes. The gross value of the shares for the accelerated RSUs was $2.1 million, or $1.1 million net of federal and state tax withholdings.

Equity Plan

On a quarterly basis, we issue shares of common stock under the ESPP and account 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 the fair value is determined by calculating the mean average of the high and low trading prices on the purchase date.

12. Income Taxes

The components of income tax expense for the years ended October 31, 2015, 2014 and 2013 are presented below.

	2015		2014		2013	
In thousands	**Federal**	**State**	Federal	State	Federal	State
Charged (Credited) to operating income:						
Current	**$ (10,449)**	**$ (289)**	$ (1,653)	$ 950	$ (3,032)	$ 919
Deferred [1][2]	**75,644**	**12,195**	70,654	13,434	67,885	11,829
Tax Credits:						
Amortization	**(167)**	**—**	(209)	—	(267)	—
Total	**65,028**	**11,906**	68,792	14,384	64,586	12,748
Charged (Credited) to other income (expense):						
Current	**9,709**	**1,449**	4,233	870	6,049	984
Deferred [1][2]	**2,249**	**(119)**	5,811	728	2,225	(646)
Total	**11,958**	**1,330**	10,044	1,598	8,274	338
Total	**$ 76,986**	**$ 13,236**	$ 78,836	$ 15,982	$ 72,860	$ 13,086

[1] Includes benefits from net operating loss (NOL) and tax carryforwards of $64.3 million and $62.3 million for the years ended October 31, 2015 and 2013, respectively.

[2] Includes the utilization of NOL carryforwards of $19.8 million and $28.6 million for the years ended October 31, 2015 and 2014, respectively.

The Tax Increase Prevention Act of 2014 (the Act), enacted December 19, 2014, retroactively extended the 50% bonus depreciation that expired December 2013 for a year to December 2014. Under the Act, we were able to claim additional depreciation deductions on our tax return for the year ended October 31, 2014. As a result of this additional depreciation, we generated a NOL for our tax year ended October 31, 2014. Prior to the Act's retroactive extension to 2014, we had anticipated utilizing NOL carryforwards to offset taxable income generated in our fiscal year 2014. The benefit from NOL and tax carryforwards for the year ended October 31, 2015 includes $61.1 million to record the retroactive impact of the Act.

A reconciliation of income tax expense at the federal statutory rate to recorded income tax expense for the years ended October 31, 2015, 2014 and 2013 is presented below.

In thousands	**2015**	2014	2013
Federal taxes at 35%	**$ 79,532**	$ 83,517	$ 77,127
State income taxes, net of federal benefit	**8,604**	10,389	8,506
Amortization of investment tax credits	**(167)**	(209)	(267)
Other, net	**2,253**	1,121	580
Total	**$ 90,222**	$ 94,818	$ 85,946

after January 1, 2015. It also provided for two additional 1% rate reductions if the state's tax collections exceed certain thresholds. In July 2015, the provision for a 1% state income tax rate reduction based on state tax collections exceeding certain thresholds under the North Carolina tax statutes was announced. Accordingly, the statutory income tax rate for North Carolina will decrease to 4% for our fiscal year 2017. We record deferred income taxes using the income tax rate in effect when the temporary difference is expected to reverse.

As a result of the state income tax rate reductions announced in July 2015, we adjusted our noncurrent deferred income tax balances during fiscal year 2015 by approximately $17.5 million for temporary differences expected to reverse at the lower future rate. We recognized a tax benefit in net income of approximately $.5 million, largely related to our regulated non-utility activities segment, and recorded the remainder of approximately $17 million as regulatory deferred income taxes as presented in noncurrent "Regulatory Liabilities" in Note 3 to the consolidated financial statements, reflecting a future benefit to our customers. During fiscal 2014, we recorded an additional $3 million for the difference in the tax rate included in our customers' rates and the rate at which the deferred taxes are expected to reverse. As of October 31, 2015, we have approximately $44 million related to the North Carolina tax rate change included in our deferred income taxes recorded in "Regulatory Liabilities," which would have been an increase to net income predominately in fiscal years 2013 and 2015 without our utility regulation. The NCUC will determine the recovery period of this regulatory liability in future proceedings. In fiscal 2013, we recognized a tax benefit in net income of approximately $1 million related to the corporate income tax reduction.

13. 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 "Noncurrent Assets" in the Consolidated Balance Sheets. Earnings or losses from equity method investments are included in "Income from equity method investments" in "Other Income (Expense)" in the Consolidated Statements of Comprehensive Income.

As of October 31, 2015, there were no amounts that represented undistributed earnings of our 50% or less owned equity method investments in our retained earnings.

Ownership Interests

We have the following membership interests in these companies as of October 31, 2015 and 2014.

Entity Name	Interest	Activity
Cardinal Pipeline Company, LLC (Cardinal)	21.49%	Intrastate pipeline located in North Carolina; regulated by the NCUC
Pine Needle LNG Company, LLC (Pine Needle)	45%	Interstate LNG storage facility located in North Carolina; regulated by the FERC
SouthStar Energy Services, LLC (SouthStar)	15%	Energy services company primarily selling natural gas in the unregulated retail gas market to residential, commercial and industrial customers in the eastern United States, primarily Georgia and Illinois
Hardy Storage Company (Hardy Storage)	50%	Underground interstate storage facility located in Hardy and Hampshire Counties, West Virginia; regulated by the FERC
Constitution Pipeline Company LLC (Constitution)	24%	To develop, construct, own and operate 124 miles of interstate natural gas pipeline and related facilities connecting shale natural gas supplies and gathering systems in Susquehanna County, Pennsylvania, to Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York; regulated by the FERC
Atlantic Coast Pipeline, LLC (ACP)	10%	To develop, construct, own and operate 564 miles of interstate natural gas pipeline with associated

compression from West Virginia through Virginia into eastern North Carolina in order to provide interstate natural gas transportation services of Marcellus and Utica gas supplies into southeastern markets; regulated by the FERC

In thousands	2015
Current assets	**$ 23,422**
Noncurrent assets	**86,109**
Current liabilities	**9,105**
Noncurrent liabilities	**—**
Revenues	**—**
Gross profit	**—**
(Loss) before income taxes	**(5,205)**

14. Variable Interest Entities

On a quarterly basis, we evaluate our variable interests in other entities, primarily ownership interests, to determine if they represent a variable interest entity (VIE) as defined by the authoritative guidance on consolidation, and if so, which party is the primary beneficiary. As of October 31, 2015, we have determined that we are not the primary beneficiary under VIE accounting guidance in any of our equity method investments, as discussed in Note 13 to the consolidated financial statements. Based on our involvement in these investments, we do not have the power to direct the activities of these investments that most significantly impact the VIE's economic performance, and we will continue to apply equity method accounting to these investments.

Our maximum loss exposure related to these equity method investments is limited to our equity investment in each entity included in "Equity method investments in non-utility activities" in "Noncurrent Assets" in the Consolidated Balance Sheets. As of October 31, 2015 and 2014, our investment balances are as follows.

In thousands	**October 31, 2015**	October 31, 2014
Cardinal	**$ 15,083**	$ 16,073
Pine Needle	**18,396**	18,689
SouthStar	**41,325**	40,965
Hardy Storage	**39,706**	37,179
Constitution	**82,403**	57,255
ACP	**10,043**	10
Total equity method investments in non-utility activities	**$ 206,956**	$ 170,171

We have also reviewed various lease arrangements, contracts to purchase, sell or deliver natural gas and other agreements in which we hold a variable interest. In these cases, we have determined that we are not the primary beneficiary of the related VIE because we do not have the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, or the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

15. Business Segments

We have three reportable business segments: regulated utility, regulated non-utility activities and unregulated non-utility activities. Our segments are identified based on products and services, regulatory environments and our current corporate organization and business decision-making activities. The regulated utility segment is the gas distribution business, where we include the operations of merchandising and its related service work and home service agreements, with activities conducted by the parent company. Although the operations of our regulated utility segment are located in three states under the jurisdiction of individual state regulatory commissions, the operations are managed as one unit having similar economic and risk characteristics within one company. Operations of our regulated non-utility activities segment are comprised of our equity method investments in joint ventures with regulated activities that are held by our wholly-owned subsidiaries. Operations of our unregulated non-utility activities segment are comprised primarily of our equity method investment in a joint venture with unregulated activities that is held by a wholly-owned subsidiary; activities of our other minor subsidiaries are also included.

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, 2015, 2014 and 2013, and as of October 31, 2015, 2014 and 2013, are presented below.

In thousands	Regulated Utility	Regulated Non-Utility Activities	Unregulated Non-Utility Activities	Total
2015				
Revenues from external customers	$ **1,371,718**	$ —	$ —	$ **1,371,718**
Margin	**727,294**	—	—	**727,294**
Operations and maintenance expenses	**294,517**	**81**	**105**	**294,703**
Depreciation	**128,704**	—	**18**	**128,722**
Operating income (loss) before income taxes	**261,963**	**(152)**	**(217)**	**261,594**
Income from equity method investments	—	**15,060**	**19,401**	**34,461**
Interest charges	**68,631**	—	—	**68,631**
Income before income taxes	**193,140**	**14,909**	**19,184**	**227,233**
Total assets	**4,742,284**	**165,630**	**41,682**	**4,949,596**
Equity method investments in non-utility activities	—	**165,630**	**41,326**	**206,956**
Construction expenditures	**443,654**	—	—	**443,654**

In thousands	Regulated Utility	Regulated Non-Utility Activities	Unregulated Non-Utility Activities	Total
2014				
Revenues from external customers	$ 1,469,988	$ —	$ —	$ 1,469,988
Margin	690,208	—	—	690,208
Operations and maintenance expenses	270,877	132	92	271,101
Depreciation	118,996	—	18	119,014
Operating income (loss) before income taxes	263,041	(183)	(203)	262,655
Income from equity method investments	—	12,318	20,435	32,753
Interest charges	54,686	—	—	54,686
Income before income taxes	206,253	12,135	20,231	238,619
Total assets [(1)]	4,432,239	129,206	41,309	4,602,754
Equity method investments in non-utility activities	—	129,206	40,965	170,171
Construction expenditures	460,444	—	—	460,444

In thousands	Regulated Utility	Regulated Non-Utility Activities	Unregulated Non-Utility Activities	Total
2013				
Revenues from external customers	$ 1,278,229	$ —	$ —	$ 1,278,229
Margin	621,490	—	—	621,490
Operations and maintenance expenses	253,120	103	78	253,301
Depreciation	112,207	—	18	112,225
Operating income (loss) before income taxes	221,528	(150)	(202)	221,176
Income from equity method investments	—	10,584	15,472	26,056
Interest charges	24,938			24,938

Income before income taxes	194,659	10,434	15,270	220,363
Total assets [1]	4,045,259	90,097	38,735	4,174,091
Equity method investments in non-utility activities	—	90,097	38,372	128,469
Construction expenditures	599,999	—	—	599,999

[1] Regulated utility total assets have been adjusted in 2014 and 2013 to reflect the netting of debt issuance costs with its debt carrying value in accordance with the 2015 adoption of new accounting guidance related to this balance sheet presentation.

Reconciliations to the consolidated financial statements for the years ended October 31, 2015, 2014 and 2013, and as of October 31, 2015 and 2014 are as follows.

In thousands		**2015**		2014		2013
Operating Income:						
Segment operating income before income taxes	$	**261,594**	$	262,655	$	221,176
Utility income taxes		**(76,934)**		(83,176)		(77,334)
Regulated non-utility activities operating loss before income taxes		**152**		183		150
Unregulated non-utility activities operating loss before income taxes		**217**		203		202
Total	$	**185,029**	$	179,865	$	144,194
Net Income:						
Income before income taxes for reportable segments	$	**227,233**	$	238,619	$	220,363
Income taxes		**(90,222)**		(94,818)		(85,946)
Total	$	**137,011**	$	143,801	$	134,417

In thousands		**2015**		2014
Consolidated Assets:				
Total assets for reportable segments	$	**4,949,596**	$	4,602,754
Eliminations/Adjustments		**161,154**		171,553
Total	$	**5,110,750**	$	4,774,307

16. Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated. For information on subsequent event disclosure items related to regulatory matters, short-term debt instruments, employee share-based plans and equity method investments, see Note 3, Note 6, Note 11 and Note 13, respectively, to the consolidated financial statements.

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

	Operating Revenues	Margin	Operating Income (Loss)	Net Income (Loss)	Earnings (Loss) Per Share of Common Stock Basic	Earnings (Loss) Per Share of Common Stock Diluted
Fiscal Year 2015						
January 31	**$ 607,271**	**$ 270,070**	**$ 105,758**	**$ 92,978**	**$ 1.18**	**$ 1.18**
April 30	**424,924**	**225,621**	**75,123**	**66,402**	**0.84**	**0.84**
July 31	**158,266**	**111,572**	**5,233**	**(8,260)**	**(0.10)**	**(0.10)**
October 31	**181,257**	**120,031**	**(1,085)**	**(14,109)**	**(0.18)**	**(0.18)**
Fiscal Year 2014						
January 31	$ 657,733	$ 261,512	$ 102,319	$ 97,572	$ 1.27	$ 1.26
April 30	462,247	211,523	67,299	62,540	0.80	0.80
July 31	164,187	104,847	3,254	(7,344)	(0.09)	(0.09)

October 31	185,821	112,326	6,993	(8,967)	(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 and our regulated utility rate designs generally result in greater earnings during the winter months. Basic earnings per share are calculated using the weighted average number of shares outstanding during the quarter. The annual amount may differ from the total of the quarterly amounts due to changes in the number of shares outstanding during the year.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Management's Evaluation of Disclosure Controls and Procedures

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

We routinely review our internal control over financial reporting and from time to time make changes intended to enhance the effectiveness of our internal control over financial reporting. There were no changes to our internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act during the fourth quarter of fiscal 2015 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

December 23, 2015

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

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

We have conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in "Internal Control—Integrated Framework" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based upon such evaluation, our management concluded that as of October 31, 2015, 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, 2015.

Piedmont Natural Gas Company, Inc.

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

/s/ Karl W. Newlin
Karl W. Newlin
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.
Charlotte, North Carolina

We have audited the internal control over financial reporting of Piedmont Natural Gas Company, Inc. and subsidiaries (the "Company") as of October 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* 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, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* 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, 2015 of the Company and our report dated December 23, 2015 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 23, 2015

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 "Board of Directors" and "Executive Officers" in our Proxy Statement for the 2016 Annual Meeting of Shareholders (2016 Proxy Statement), 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 2016 Proxy Statement, 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 2016 Proxy Statement, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Ethics and Business Conduct that is applicable to all our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer, which serves as the code of ethics applicable to our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions under Item 406(b) of Regulation S-K. The Code of Ethics and Business Conduct is available on the "For Investors-Corporate Governance" section of our website at www.piedmontng.com. If we amend or grant a waiver, including an implicit waiver, from the Code of Ethics and Business Conduct that apply to the principal executive officer, principal financial officer and principal accounting officer 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 "For Investors-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 2016 Proxy Statement, 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 2016 Proxy Statement, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning securities authorized for issuance under our equity compensation plans is set forth in the section entitled "Equity Compensation Plan Information" in our 2016 Proxy Statement, 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 "Director Independence and Related Person Transactions" in our 2016 Proxy Statement, 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 "Proposal 2 – Ratification of the Appointment of Deloitte & Touche LLP As Independent Registered Public Accounting Firm For Fiscal Year 2016" in our 2016 Proxy Statement, 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, 2015, are included in Item 8 of this report as follows:

Consolidated Balance Sheets – October 31, 2015 and 2014
Consolidated Statements of Comprehensive Income – Years Ended October 31, 2015, 2014 and 2013
Consolidated Statements of Cash Flows – Years Ended October 31, 2015, 2014 and 2013
Consolidated Statements of Stockholders' Equity – Years Ended October 31, 2015, 2014 and 2013
Notes to Consolidated Financial Statements
Report of Independent Registered Public Accounting Firm

(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 10.17 are management contracts or compensatory plans or arrangements.

2.1 Agreement and Plan of Merger, dated as of October 24, 2015, by and among Duke Energy Corporation, Forest Subsidiary, Inc. and Piedmont Natural Gas Company, Inc. (incorporated by reference to Exhibit 2.1, Form 8-K dated October 26, 2015).

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

3.2 Bylaws of Piedmont Natural Gas Company, Inc., as Amended and Restated Effective September 8, 2011 (incorporated by reference to Exhibit 3.1, Form 8-K dated September 13, 2011).

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

4.2	Amendment to September 1992 Note Agreement, dated as of September 16, 2005, by and between Piedmont and Provident Life and Accident Insurance Company (incorporated by reference to 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 (incorporated by reference to Exhibit 4.1, Form S-3 Registration Statement No. 33-59369).

4.4	Medium-Term Note, Series A, dated as of October 6, 1993 (incorporated by reference to 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 (incorporated by reference to Exhibit 4.2, Form S-3 Registration Statement No. 33-59369).
4.6	Medium-Term Note, Series A, dated as of September 19, 1994 (incorporated by reference to Exhibit 4.9, Form 10-K for the fiscal year ended October 31, 1994).
4.7	Form of Master Global Note (incorporated by reference to 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 (incorporated by reference to 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 (incorporated by reference to Exhibit 4.11, Form 10-K for the fiscal year ended October 31, 1996).
4.10	Form of Master Global Note (incorporated by reference to Exhibit 4.4, Form S-3 Registration Statement No. 333-26161).
4.11	Pricing Supplement of Medium-Term Notes, Series C, dated September 15, 1999 (incorporated by reference to Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement Nos. 33-59369 and 333-26161).
4.12	Second Supplemental Indenture, dated as of June 15, 2003, between Piedmont and Citibank, N.A., Trustee (incorporated by reference to Exhibit 4.3, Form S-3 Registration Statement No. 333-106268).
4.13	Form of 6% Medium-Term Note, Series E, dated as of December 19, 2003 (incorporated by reference to Exhibit 99.2, Form 8-K, dated December 23, 2003).
4.14	Third Supplemental Indenture, dated as of June 20, 2006, between Piedmont Natural Gas Company, Inc. and Citibank, N.A., as trustee (incorporated by reference to Exhibit 4.1, Form 8-K dated June 20, 2006).
4.15	Agreement of Resignation, Appointment and Acceptance dated as of March 29, 2007, by and among Piedmont Natural Gas Company, Inc., Citibank, N.A., and The Bank of New York Trust Company, N.A. (incorporated by reference to Exhibit 4.1, Form 10-Q for quarter ended April 30, 2007).
4.16	Note Purchase Agreement, dated as of May 6, 2011, among Piedmont Natural Gas Company, Inc. and the Purchasers party thereto (incorporated by reference to Exhibit 10, Form 8-K, dated

May 12, 2011).

4.17	Form of 2.92% Series A Senior Notes due June 6, 2016 (incorporated by reference to Exhibit 4.1, Form 8-K dated May 12, 2011).
4.18	Form of 4.24% Series B Senior Notes due June 6, 2021 (incorporated by reference to Exhibit 4.2, Form 8-K dated May 12, 2011).

4.19	Fourth Supplemental Indenture, dated as of May 6, 2011, between Piedmont Natural Gas Company, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2, Form S-3-ASR Registration Statement No. 333-175386).
4.20	Amendment to September 1992 Note Agreement dated as of April 15, 2011 by and between Piedmont Natural Gas Company, Inc., and Provident Life and Accident Insurance Company (incorporated by reference to Exhibit 10.3, Form 10-Q for the quarter ended April 30, 2011).
4.21	Note Purchase Agreement, dated as of March 27, 2012, among Piedmont Natural Gas Company, Inc. and the Purchasers party thereto (incorporated by reference to Exhibit 10.1, Form 8-K dated March 29, 2012).
4.22	Form of 3.47% Series A Senior Notes due July 16, 2027 (incorporated by reference to Exhibit 4.1, Form 8-K dated March 29, 2012).
4.23	Form of 3.57% Series B Senior Notes due July 16, 2027 (incorporated by reference to Exhibit 4.2, Form 8-K dated March 29, 2012).
4.24	Corporate Commercial Paper Master Note dated March 1, 2012 between U.S. Bank National Association as Paying Agent and Piedmont Natural Gas Company, Inc. as Issuer (incorporated by reference to Exhibit 4.1, Form 10-Q for the quarter ended April 30, 2012).
4.25	Fifth Supplemental Indenture, dated August 1, 2013, between the Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 4.1, Form 8-K dated August 1, 2013).
4.26	Form of 4.65% Senior Notes due 2043 (incorporated by reference to Exhibit 4.2, Form 8-K dated August 1, 2013).
4.27	Sixth Supplemental Indenture, dated September 18, 2014, between the Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 4.1, Form 8-K dated September 18, 2014).
4.28	Form of 4.10% Senior Notes due 2034 (incorporated by reference to Exhibit 4.2, Form 8-K dated September 18, 2014).
4.29	Third Amendment to September 1992 Note Agreement, dated as of October 15, 2014, between the Company and Provident Life and Accident Insurance Company (incorporated by reference to Exhibit 4.29, Form 10-K for the fiscal year ended October 31, 2014).
4.30	Seventh Supplemental Indenture, dated September 14, 2015, between the Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 4.1, Form 8-K dated September 14, 2015).

4.31	Form of 3.60% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2, Form 8-K dated September 14, 2015).
	Compensatory Contracts:
10.1	Form of Director Retirement Benefits Agreement with outside directors, dated September 1, 1999 (incorporated by reference to Exhibit 10.54, Form 10-K for the fiscal year ended October 31, 1999).

10.2	Severance Agreement with Thomas E. Skains, dated September 4, 2007 (substantially identical agreements have been entered into as of the same date with Franklin H. Yoho, Kevin M. O'Hara and Jane R. Lewis-Raymond) (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2007).
10.3	Schedule of Severance Agreements with Executives (incorporated by reference to Exhibit 10.2a, Form 10-Q for the quarter ended July 31, 2007).
10.4	Piedmont Natural Gas Company, Inc. Incentive Compensation Plan as Amended and Restated Effective December 15, 2010 (incorporated by reference to Appendix A, Form DEF14A dated January 14, 2011).
10.5	Form of Performance Unit Award Agreement.
10.6	Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan, dated as of December 8, 2008, effective January 1, 2009 (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended January 31, 2009).
10.7	Amendment No. 1 to Director Retirement Benefits Agreements with outside directors, dated as of December 31, 2008 (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2009).
10.8	Severance Agreement between Piedmont Natural Gas Company, Inc. and Karl W. Newlin, dated as of June 4, 2010 (incorporated by reference to Exhibit 10.3, Form 10-Q for the quarter ended July 31, 2010).
10.9	Instrument of Amendment for Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan, dated as of January 23, 2012, by Piedmont Natural Gas Company, Inc. (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended January 31, 2012).
10.10	2011 Retention Award Agreement, dated December 15, 2011, between Piedmont Natural Gas Company, Inc. and Thomas E. Skains (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended January 31, 2012).
10.11	Severance Agreement, dated February 1, 2012, between Piedmont Natural Gas Company, Inc. and Victor M. Gaglio (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended April 30, 2012).
10.12	Amended and Restated Employment Agreement, dated May 25, 2012, between Piedmont Natural Gas Company, Inc. and Thomas E. Skains (substantially identical agreements have been entered into with Victor M. Gaglio, Jane R. Lewis-Raymond, Karl W. Newlin, Kevin M. O'Hara and Franklin H. Yoho) (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2012).
10.13	Schedule of Amended and Restated Employment Agreements with Executives (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2012).

10.14	Resolution of Board of Directors, June 6, 2014, establishing compensation for non-management directors (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2014).
10.15	Piedmont Natural Gas Company Employee Stock Purchase Plan Amended and Restated as of November 1, 2014, dated as of January 30, 2015 (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended January 31, 2015).

10.16 Piedmont Natural Gas Company, Inc. Voluntary Deferral Plan, amended and restated effective March 31, 2015, dated May 1, 2015 (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2015).

10.17 Resolution of Board of Directors, June 5, 2015, establishing compensation for non-management directors (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2015).

Other Contracts:

10.18 Form of Commercial Paper Dealer Agreement between Piedmont Natural Gas Company, Inc. and Dealers party thereto (incorporated by reference to Exhibit 10.3, Form 10-Q for the quarter ended April 30, 2012).

10.19 Amended and Restated Credit Agreement dated as of October 1, 2012 among Piedmont Natural Gas Company, Inc., Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender, L/C Issuer and a Lender, and Branch Banking and Trust Company, Bank of America, N.A., JPMorgan Chase Bank, N.A., PNC Bank, National Association, U.S. Bank National Association and Royal Bank of Canada, each a Lender (incorporated by reference to Exhibit 10.34, Form 10-K for the fiscal year ended October 31, 2012).

10.20 Amended and Restated Limited Liability Company Agreement of Constitution Pipeline Company, LLC dated April 9, 2012, by and among Williams Partners Operating LLC and Cabot Pipeline Holdings LLC (incorporated by reference to Exhibit 10.1, Form 10-Q for the quarter ended January 31, 2013).

10.21 First Amendment to Amended and Restated Limited Liability Company Agreement of Constitution Pipeline Company, LLC, dated as of November 9, 2012, by and among Constitution Pipeline Company, LLC, Williams Partners Operating LLC, Cabot Pipeline Holdings LLC, and Piedmont Constitution Pipeline Company, LLC (incorporated by reference to Exhibit 10.2, Form 10-Q for the quarter ended January 31, 2013).

10.22 Second Amendment to Amended and Restated Limited Liability Company Agreement of Constitution Pipeline Company, LLC, dated as of May 29, 2013, by and among Constitution Pipeline Company, LLC, Williams Partners Operating LLC, Cabot Pipeline Holdings LLC, Piedmont Constitution Pipeline Company, LLC, and Capitol Energy Ventures Corp. (incorporated by reference to Exhibit 99.1, Form 8-K filed September 4, 2013).

10.23 Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of September 1, 2013, by and between Georgia Natural Gas Company and Piedmont Energy Company (incorporated by reference to Exhibit 10.39, Form 10-K for the fiscal year ended October 31, 2013).

10.24 Increasing Lender Agreement dated as of November 1, 2013 among Wells Fargo Bank, National Association, Bank of America, N.A., Branch Banking and Trust Company, JPMorgan Chase Bank, N.A., PNC Bank, National Association, U.S. Bank National Association and Royal Bank of Canada, each as a Lender (incorporated by reference to Exhibit 10.1, Form 8-K dated November 4, 2013).

10.25 * Limited Liability Company Agreement of Atlantic Coast Pipeline, LLC, dated as of September 2, 2014, by and between Dominion Atlantic Coast Pipeline, LLC, Duke Energy ACP, LLC, Piedmont ACP Company, LLC, and Maple Enterprise Holdings, Inc. (incorporated by reference to Exhibit 10.35, Form 10-K for the fiscal year ended October 31, 2014).

10.26 ATM Equity Offering Sales Agreement dated January 7, 2015 between the Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated (incorporated by reference to Exhibit 1.1, Form 8-K dated January 7, 2015).

10.27	ATM Equity Offering Sales Agreement dated January 7, 2015 between the Company and J.P. Morgan Securities LLC (incorporated by reference to Exhibit 1.2, Form 8-K dated January 7, 2015).
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.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.DEF	XBRL Taxonomy Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* Certain portions of this Exhibit have been omitted pursuant to a request for confidential treatment. The non-public information has been filed separately with the SEC pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

Attached as Exhibit 101 to this Annual Report are the following documents formatted in extensible business reporting language (XBRL): (1) Document and Entity Information; (2) Consolidated Balance Sheets as of October 31, 2015 and 2014; (3) Consolidated Statements of Comprehensive Income for the years ended October 31, 2015, 2014 and 2013; (4) Consolidated Statements of Cash Flows for the years ended October 31, 2015, 2014 and 2013; (5) Consolidated Statements of Stockholders' Equity for the years ended October 31, 2015, 2014 and 2013; and Notes to Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Piedmont Natural Gas Company, Inc.

(Registrant)

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

Date: December 23, 2015

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 23, 2015	
/s/ Karl W. Newlin Karl W. Newlin	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date: December 23, 2015	
/s/ Jose M. Simon Jose M. Simon	Vice President and Controller (Principal Accounting Officer)
Date: December 23, 2015	

Signature	Title
/s/ E. James Burton E. James Burton	Director
/s/ Malcolm E. Everett III Malcolm E. Everett III	Director
/s/ Gary A. Garfield Gary A. Garfield	Director
/s/ Frank B. Holding, Jr. Frank B. Holding, Jr.	Director
/s/ Frankie T. Jones, Sr. Frankie T. Jones, Sr.	Director
/s/ Vicki W. McElreath Vicki W. McElreath	Director
/s/ Thomas M. Pashley Thomas M. Pashley	Director
/s/ Minor M. Shaw Minor M. Shaw	Director
/s/ Jo Anne Sanford Jo Anne Sanford	Director
/s/ David E. Shi David E. Shi	Director
/s/ Michael C. Tarwater Michael C. Tarwater	Director
/s/ Phillip D. Wright Phillip D. Wright	Director

Piedmont Natural Gas Company, Inc.
Form 10-K
For the Fiscal Year Ended October 31, 2015

Exhibits

10.5	Form of Performance Unit Award Agreement
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