PIEDMONT NATURAL GAS CO INC
Form 10-Q
September 08, 2005

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended July 31, 2005

or

o **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.)
1915 Rexford Road, Charlotte, North Carolina	28211
(Address of principal executive offices)	(Zip Code)

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

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 þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes þ No o

Indicate by check mark whether the registrant is a shell Company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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

Class	Outstanding at September 1, 2005
Common Stock, no par value	76,595,888

PART 1. FINANCIAL INFORMATION

Item 1. Financial Statements

Piedmont Natural Gas Company, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

(In thousands)

	July 31, 2005	October 31, 2004
Utility Plant, at original cost	$ 2,567,967	$ 2,474,796
Less accumulated depreciation	661,167	624,973
Utility plant, net	1,906,800	1,849,823
Other Physical Property (net of accumulated depreciation of $1,918 in 2005 and $1,782 in 2004)	763	973
Current Assets:		
Cash and cash equivalents	5,733	5,676
Restricted cash	12,971	12,732
Marketable securities, at market value		1,857
Receivables (less allowance for doubtful accounts of $3,087 in 2005 and $1,086 in 2004)	99,257	70,987
Unbilled utility revenues	12,796	25,711
Gas in storage	104,333	128,465
Gas purchase options, at fair value	9,594	13,182
Income taxes receivable	22,632	11,533
Amounts due from customers	39,253	28,832
Prepayments	27,237	38,709
Other	5,216	4,823
Total current assets	339,022	342,507
Investments, Deferred Charges and Other Assets:		
Equity method investments in non-utility activities	68,366	65,322
Goodwill	47,850	48,151
Unamortized debt expense	4,932	5,261
Other	35,092	31,138
Total investments, deferred charges and other assets	156,240	149,872
Total	$ 2,402,825	$ 2,343,175

CAPITALIZATION AND LIABILITIES

	2005	2004
Capitalization:		
Common stock equity:		
Common stock, no par value, 100,000 shares authorized; outstanding, 76,671 in 2005 and 76,670 in 2004	$ 562,652	$ 563,667
Retained earnings	346,127	291,397
Accumulated other comprehensive income (loss)	(3,470)	(166)
Total common stock equity	905,309	854,898
Long-term debt	625,000	660,000
Total capitalization	1,530,309	1,514,898
Current Liabilities:		
Current maturities of long-term debt and sinking fund requirements	35,000	
Notes payable	84,000	109,500
Accounts payable	92,895	99,599
Deferred income taxes	48,898	20,687
Income taxes accrued		306
General taxes accrued	13,030	17,097
Amounts due to customers	16,800	26,379
Accrued gas cost on unbilled utility revenues	1,249	2,479
Other	30,905	37,418
Total current liabilities	322,777	313,465
Deferred Credits and Other Liabilities:		
Deferred income taxes	217,147	202,155
Unamortized federal investment tax credits	4,085	4,492
Asset retirement obligations	283,296	266,700
Other	45,211	41,465
Total deferred credits and other liabilities	549,739	514,812
Total	$ 2,402,825	$ 2,343,175

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Operations (Unaudited)
(In thousands)

	Three Months Ended July 31		Nine Months Ended July 31		Twelve Months Ended July 31	
	2005	2004	2005	2004	2005	2004
Operating Revenues	$ 232,912	$ 214,750	$ 1,421,503	$ 1,315,933	$ 1,635,308	$ 1,495,357
Cost of Gas	156,296	145,022	1,001,610	903,870	1,139,110	1,021,422
Margin	76,616	69,728	419,893	412,063	496,198	473,935
Operating Expenses:						
Operations and maintenance	50,218	47,803	152,795	148,014	205,063	186,054
Depreciation	21,523	20,886	63,260	61,549	83,988	78,818
General taxes	7,660	6,974	23,433	20,397	30,046	26,028
Income taxes	(5,769)	(7,400)	57,588	57,385	51,582	53,535
Total operating expenses	73,632	68,263	297,076	287,345	370,679	344,435
Operating Income	2,984	1,465	122,817	124,718	125,519	129,500
Other Income (Expense):						
Income from equity method investments	4,077	3,995	24,537	25,375	26,543	27,256
Gain on sale of equity method investments				4,683		4,683
Gain on sale of marketable securities			1,525		1,525	
Allowance for equity funds used during construction	304	323	920	971	1,162	1,268
Non-operating income	2,322	1,008	2,843	2,098	3,031	2,720
Charitable contributions	(109)	26	(361)	(845)	(8,640)	(1,052)
Non-operating expense	(40)	(26)	(125)	(111)	(338)	(211)
Income taxes	(2,761)	(2,259)	(11,465)	(12,896)	(9,237)	(14,045)
Total other income (expense), net of tax	3,793	3,067	17,874	19,275	14,046	20,619

Utility Interest Charges	11,141	12,664	34,147	36,199	45,578	46,463
Income (Loss) Before Minority Interest in Income of Consolidated Subsidiary	(4,364)	(8,132)	106,544	107,794	93,987	103,656
Less Minority Interest in Income (Loss) of Consolidated Subsidiary	302	25	301	70	280	889
Net Income (Loss)	($ 4,666)	($ 8,157)	$ 106,243	$ 107,724	$ 93,707	$ 102,767
Average Shares of Common Stock:						
Basic	76,684	76,436*	76,699	73,594*	76,684*	71,977*
Diluted	76,684	76,436*	76,913	73,776*	76,916*	72,177*
Earnings (Loss) Per Share of Common Stock:						
Basic	($ 0.06)	($ 0.11)*	$ 1.39	$ 1.46*	$ 1.22*	$ 1.43*
Diluted	($ 0.06)	($ 0.11)*	$ 1.38	$ 1.46*	$ 1.22*	$ 1.42*
Cash Dividends Per Share of Common Stock	$ 0.23	$ 0.215*	$ 0.675	$ 0.6375*	$ 0.89*	0.845*

* Reflects a two-for-one stock split effective October 11, 2004.

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Cash Flows (Unaudited)
(In thousands)

	Three Months Ended July 31		Nine Months Ended July 31		Twelve Months Ended July 31	
	2005	2004	2005	2004	2005	2004
Cash Flows from Operating Activities:						
Net income (loss)	($4,666)	($8,157)	$ 106,243	$ 107,724	$ 93,707	$ 102,767
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation and amortization	23,937	22,198	68,302	65,292	90,346	83,148
Undistributed earnings from equity method investments	(4,077)	(3,995)	(24,537)	(25,375)	(26,543)	(27,256)
Gain on sale of equity method investments				(4,683)		(4,683)
Change in assets and liabilities	(43,647)	(60,457)	15,888	58,520	(30,686)	20,597
Other, net	(4,969)	(5,955)	(949)	(899)	(4,872)	(1,649)
Net cash provided by (used in) operating activities	(33,422)	(56,366)	164,947	200,579	121,952	172,924
Cash Flows from Investing Activities:						
Utility construction expenditures	(53,204)	(37,104)	(136,650)	(97,384)	(178,411)	(120,995)
Reimbursements from bond fund	3,970	7,285	23,253	23,459	41,291	27,220
Contributions to equity method investments	(1,566)		(1,886)		(1,999)	
Distributions from equity method investments	1,196	1,277	23,154	24,761	24,684	26,009
Proceeds from sale of equity method investments				36,096		36,096
Proceeds from sale of marketable securities			2,394		2,394	
Proceeds from sale of corporate office, net of expenses	6,660		6,660		6,660	
Proceeds from sale of non-utility plant			120		120	
Purchase of NCNG and EasternNC, net of cash received in the twelve months ended July 31, 2004, of $7,185				(271)		(450,439)
Increase in restricted cash	(92)	(5,780)	(239)	(5,837)	(385)	(5,906)

Other	(1,267)	(335)	(1,639)	1,953	(1,634)	2,090
Net cash used in investing activities	(44,303)	(34,657)	(84,833)	(17,223)	(107,280)	(485,925)
Cash Flows from Financing Activities:						
Increase (Decrease) in notes payable, net	84,000	27,000	(25,500)	(82,500)	57,000	(18,000)
Repayment of commercial paper				(445,559)		
Proceeds from issuance of long-term debt				198,334		198,334
Debt offering costs		12		(276)		(424)
Retirement of long-term debt		(2,000)		(2,000)		(2,000)
Proceeds from sale of common stock, net of expenses				173,828		173,828
Issuance of common stock through dividend reinvestment and employee stock plans	5,276	5,401	18,359	14,769	23,607	18,810
Repurchases of common stock	(8,191)		(21,170)		(25,657)	
Dividends paid	(17,626)	(16,429)	(51,746)	(46,791)	(68,222)	(60,725)
Net cash provided by (used in) financing activities	63,459	13,984	(80,057)	(190,195)	(13,272)	309,823
Net Increase (Decrease) in Cash and Cash Equivalents	(14,266)	(77,039)	57	(6,839)	1,400	(3,178)
Cash and Cash Equivalents at Beginning of Period	19,999	81,372	5,676	11,172	4,333	7,511
Cash and Cash Equivalents at End of Period	$ 5,733	$ 4,333	$ 5,733	$ 4,333	$ 5,733	$ 4,333
Noncash Investing and Financing Activities Related to Acquisitions of NCNG and EasternNC:						
Fair value/book value of assets acquired		$ 3,811		($2,694)		$ 508,441
Cash paid				(271)		(457,624)
Adjustment of estimated working capital to actual				271		2,281
Liabilities assumed		$ 3,811		($2,694)		$ 53,098

See notes to condensed consolidated financial statements.

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income (Unaudited)
(In thousands)

	Three Months Ended July 31		Nine Months Ended July 31		Twelve Months Ended July 31	
	2005	2004	2005	2004	2005	2004
Net Income (Loss)	($4,666)	($8,157)	$ 106,243	$ 107,724	$ 93,707	$ 102,767
Other Comprehensive Income, net of tax:						
Minimum pension liability adjustment			(2,748)		(2,748)	
Reclassification adjustment of realized gain on marketable securities included in net income			(945)		(945)	
Unrealized income on marketable securities		404	348	404	541	404
Unrealized income (loss) from hedging activities of equity method investees	(515)	515	1,714	506	1,590	117
Reclassification adjustment of realized (income) loss from hedging activities of equity method investees included in net income	16	1	(1,673)	706	(1,592)	996
Total Comprehensive Income (Loss)	($5,165)	($7,237)	$ 102,939	$ 109,340	$ 90,553	$ 104,284

See notes to condensed consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. The condensed consolidated financial statements have not been audited. These financial statements and other information included in this quarterly report should be read in conjunction with the Consolidated Financial Statements and Notes included in our Form 10-K/A for the year ended October 31, 2004.

2. In our opinion, the unaudited condensed consolidated financial statements include all normal recurring adjustments necessary for a fair statement of financial position at July 31, 2005 and October 31, 2004, and the results of operations and cash flows for the three, nine and twelve months ended July 31, 2005 and 2004. Our business is seasonal in nature. The results of operations for the three and nine months ended July 31, 2005, do not necessarily reflect the results to be expected for the full year.

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

3. We follow Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71). Statement 71 provides that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying Statement 71, we capitalize certain costs and benefits as regulatory assets and liabilities, respectively, pursuant to orders of the state regulatory commissions, either in general rate proceedings or expense deferral proceedings, in order to provide for recovery from or refund to utility customers in future periods. The amounts recorded as regulatory assets in the condensed consolidated balance sheets as of July 31, 2005 and October 31, 2004, were $72.1 million and $59.3 million, respectively. The amounts recorded as regulatory liabilities in the condensed consolidated balance sheets as of July 31, 2005 and October 31, 2004, were $311.7 million and $304.9 million, respectively.

4. All of our goodwill is attributable to the regulated utility segment. The balance in goodwill as of October 31, 2004 and July 31, 2005, and the changes for the nine months ended July 31, 2005, are presented below.

In thousands	
Balance as of October 31, 2004	$ 48,151
Minority interest in income of Eastern North Carolina Natural Gas Company (EasternNC)	(301)
Balance as of July 31, 2005	$ 47,850

5. Components of the net periodic benefit cost for our defined-benefit pension plans and other postretirement benefit plan for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below. All amounts reflect the impact of the acquisition of North Carolina Natural Gas Corporation (NCNG) effective as of the close of business on September 30, 2003.

In thousands	Pension Benefits 2005	Pension Benefits 2004	Other Benefits 2005	Other Benefits 2004
Three Months Ended July 31				
Service cost	$ 2,947	$ 2,349	$ 348	$ 341
Interest cost	3,242	3,021	538	663
Expected return on plan assets	(4,232)	(4,113)	(258)	(231)
Amortization of transition obligation			220	220
Amortization of prior-service cost	234	233	321	258
Amortization of actuarial (gain) loss	143			95
Net periodic benefit cost	$ 2,334	$ 1,490	$ 1,169	$ 1,346
Nine Months Ended July 31				
Service cost	$ 5,639	$ 4,699	$ 696	$ 682
Interest cost	6,409	6,042	1,076	1,325
Expected return on plan assets	(8,297)	(8,110)	(515)	(461)
Amortization of transition obligation			439	440
Amortization of prior-service cost	466	465	642	515
Amortization of actuarial (gain) loss	189			191
Net periodic benefit cost	$ 4,406	$ 3,096	$ 2,338	$ 2,692
Twelve Months Ended July 31				
Service cost	$ 10,848	$ 8,828	$ 1,358	$ 1,266
Interest cost	12,596	11,690	2,173	2,573
Expected return on plan assets	(16,476)	(15,499)	(1,004)	(897)
Amortization of transition obligation		3	879	879
Amortization of prior-service cost	932	931	1,221	1,030
Amortization of actuarial (gain) loss	236	(210)	(6)	336
Net periodic benefit cost	$ 8,136	$ 5,743	$ 4,621	$ 5,187

During the quarter ended July 31, 2005, we contributed $17.3 million to the pension plans and $2.7 million to the other postretirement benefits plan.

6. We compute basic earnings per share using the weighted average number of shares of Common Stock outstanding during each period. A reconciliation of basic and diluted earnings per share for the three, nine and twelve months ended July 31, 2005 and 2004, is presented below. All shares and per share amounts reflect a two-for-one stock split effective October 11, 2004.

In thousands except per share amounts	Three Months 2005	Three Months 2004	Nine Months 2005	Nine Months 2004	Twelve Months 2005	Twelve Months 2004
Net Income (Loss)	$ (4,666)	$ (8,157)	$ 106,243	$ 107,724	$ 93,707	$ 102,767
	76,684	76,436	76,699	73,594	76,684	71,977

Average shares of Common Stock outstanding for basic earnings per share				
Contingently issuable shares under the Long-Term Incentive Plan *	214	182	232	200

In thousands except per share amounts	Three Months 2005	Three Months 2004	Nine Months 2005	Nine Months 2004	Twelve Months 2005	Twelve Months 2004
Average shares of dilutive stock	76,684	76,436	76,913	73,776	76,916	72,177
Earnings (Loss) Per Share of Common Stock:						
Basic	$ (.06)	$ (.11)	$ 1.39	$ 1.46	$ 1.22	$ 1.43
Diluted	$ (.06)	$ (.11)	$ 1.38	$ 1.46	$ 1.22	$ 1.42

* For the three months ended July 31, 2005 and 2004, the inclusion of 213 and 170 contingently issuable shares, respectively, would have been antidilutive.

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

Operations of the regulated utility segment are reflected in operating income in the condensed consolidated statements of operations. Operations of the non-utility activities segment are included in the Other Income (Expense) section of the condensed consolidated statements of operations in Income from equity method investments and Non-operating income.

We evaluate the performance of the regulated utility segment based on margin, operations and maintenance expenses and operating income. We evaluate the performance of the non-utility activities segment based on earnings from the ventures and the return on our investments in the ventures. The basis of segmentation and the basis of the measurement of segment profit or loss are the same as reported in the consolidated financial statements for the year ended October 31, 2004.

Operations by segment for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below.

In thousands	Regulated Utility 2005	Regulated Utility 2004	Non-utility Activities 2005	Non-utility Activities 2004	Total 2005	Total 2004
Three Months Ended July 31						
Revenues from external customers	$ 232,912	$ 214,750	$	$	$ 232,912	$ 214,750
Margin	76,616	69,728			76,616	69,728
	50,218	47,803	56	32	50,274	47,835

Operations and maintenance expenses						
Operating income (loss)	(2,785)	(5,935)	(135)	(83)	(2,920)	(6,018)
Income from equity method investments			4,077	3,995	4,077	3,995
Income (loss) before income taxes and minority interest	(11,206)	(17,362)	3,834	4,089	(7,372)	(13,273)
Equity method investments in non-utility activities			68,366	64,864	68,366	64,864

	Regulated Utility		Non-utility Activities		Total	
In thousands	2005	2004	2005	2004	2005	2004
Nine Months Ended July 31						
Revenues from external customers	$ 1,421,503	$ 1,315,933	$	$	$ 1,421,503	$ 1,315,933
Margin	419,893	412,063			419,893	412,063
Operations and maintenance expenses	152,795	148,014	211	119	153,006	148,133
Operating income (loss)	180,405	182,103	(394)	(180)	180,011	181,923
Income from equity method investments			24,537	25,375	24,537	25,375
Income before income taxes and minority interest	150,172	147,695	25,425	30,380	175,597	178,075
Equity method investments in non-utility activities			68,366	64,864	68,366	64,864
Twelve Months Ended July 31						
Revenues from external customers	$ 1,635,308	$ 1,495,357	$	$	$ 1,635,308	$ 1,495,357
Margin	496,198	473,935			496,198	473,935
Operations and maintenance expenses	205,063	186,054	265	174	205,328	186,228
Operating income (loss)	177,101	183,035	(448)	(285)	176,653	182,750
Income from equity method investments			26,543	27,256	26,543	27,256
Income before income taxes and minority interest	127,522	139,138	27,284	32,098	154,806	171,236
Equity method investments in non-utility activities			68,366	64,864	68,366	64,864

Reconciliations to the condensed consolidated statements of operations for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below.

	Three Months		Nine Months		Twelve Months	
In thousands	2005	2004	2005	2004	2005	2004
Operating Income:						
Segment operating income (loss)	$ (2,920)	$ (6,018)	$ 180,011	$ 181,923	$ 176,653	$ 182,750

Utility income taxes	5,769	7,400	(57,588)	(57,385)	(51,582)	(53,535)
Non-utility activities	135	83	394	180	448	285
Operating income	$ 2,984	$ 1,465	$ 122,817	$ 124,718	$ 125,519	$ 129,500
Net Income:						
Income (loss) before income taxes and minority interest for reportable segments	$ (7,372)	$ (13,273)	$ 175,597	$ 178,075	$ 154,806	$ 171,236
Income taxes	3,008	5,141	(69,053)	(70,281)	(60,819)	(67,580)
Less minority interest income	302	25	301	70	280	889
Net income (loss)	$ (4,666)	$ (8,157)	$ 106,243	$ 107,724	$ 93,707	$ 102,767

8. The condensed 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 business is recorded in Equity method investments in non-utility activities in the condensed consolidated balance sheets. Earnings or losses from equity method investments are recorded in Income from equity method investments in Other Income (Expense) in the condensed consolidated statements of operations.

As of July 31, 2005, the amount of retained earnings that represented undistributed earnings of equity method investments was $25.5 million.

We own 21.48% of the membership interests in Cardinal Pipeline Company, L.L.C., a North Carolina limited liability company. Cardinal owns and operates an intrastate natural gas pipeline in North Carolina and is regulated by the North Carolina Utilities Commission (NCUC).

We have related party transactions as a transportation customer of Cardinal and we record in cost of gas the transportation costs charged by Cardinal. These costs for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below.

	Three Months		Nine Months		Twelve Months	
In thousands	2005	2004	2005	2004	2005	2004
Transportation Costs	$ 1,181	$ 1,181	$ 3,504	$ 3,520	$ 4,684	$ 4,125

As of July 31, 2005 and 2004, we owed Cardinal $.4 million.

Summarized financial information provided to us by Cardinal for 100% of Cardinal as of and for the three and nine months ended June 30, 2005 and 2004, is presented below.

	Three Months		Nine Months	
In thousands	2005	2004	2005	2004
Revenues	$ 3,870	$ 3,870	$ 11,612	$ 11,654
Gross profit	3,870	3,870	11,612	11,654
Income before income taxes	2,124	1,828	6,167	5,913
Total assets	96,360	99,897	96,360	99,897

We own 40.0587% of the membership interests in Pine Needle LNG Company, L.L.C., a North Carolina limited liability company. Pine Needle owns an interstate liquefied natural gas (LNG) storage facility in North Carolina and is regulated by the Federal Energy Regulatory Commission (FERC).

We have related party transactions as a customer of Pine Needle and we record in cost of gas the storage costs charged by Pine Needle. These costs for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below.

	Three Months		Nine Months		Twelve Months	
In thousands	2005	2004	2005	2004	2005	2004
Storage Costs	$ 3,162	$ 3,100	$ 9,276	$ 9,170	$ 12,377	$ 11,913

As of July 31, 2005 and 2004, we owed Pine Needle $1.1 million and $1 million, respectively.
Summarized financial information provided to us by Pine Needle for 100% of Pine Needle as of and for the three and nine months ended June 30, 2005 and 2004, is presented below.

	Three Months		Nine Months	
In thousands	2005	2004	2005	2004
Revenues	$ 5,380	$ 5,177	$ 15,172	$ 14,700
Gross profit	5,380	5,177	15,172	14,700
Income before income taxes	2,364	2,272	6,958	6,910
Total assets	112,815	116,236	112,815	116,236

We own 30% of the membership interests in SouthStar Energy Services LLC, a Delaware limited liability company. Under the terms of an amended and restated LLC operating agreement effective January 1, 2004, earnings and losses are allocated 25% to us and 75% to the other member. SouthStar sells natural gas to residential, commercial and industrial customers in the southeastern United States; however, SouthStar conducts most of its business in the unregulated retail gas market in Georgia.
We have related party transactions as SouthStar purchases wholesale gas supplies from us. Operating revenues from these sales for the three, nine and twelve months ended July 31, 2005 and 2004, are presented below.

	Three Months		Nine Months		Twelve Months	
In thousands	2005	2004	2005	2004	2005	2004
Operating Revenues	$ 2,261	$ 1,100	$ 8,271	$ 1,246	$ 9,691	$ 1,246

As of July 31, 2005 and 2004, SouthStar owed us $.7 million and $.4 million, respectively.
Summarized financial information provided to us by SouthStar for 100% of SouthStar as of and for the three and nine months ended June 30, 2005 and 2004, is provided below.

	Three Months		Nine Months	
In thousands	2005	2004	2005	2004
Revenues	$ 160,246	$ 148,381	$ 718,796	$ 662,784
Gross profit	23,593	23,618	124,838	105,772
Income before income taxes	10,411	10,528	81,567	69,788
Total assets	168,532	162,506	168,532	162,506

9. We purchase natural gas for our regulated operations for resale under tariffs approved by the state regulatory commissions having jurisdiction over the service area where the customer is located. We recover the cost of gas purchased for regulated operations through purchased gas cost recovery mechanisms. We structure the pricing, quantity and term provisions of our gas supply contracts to maximize flexibility and minimize cost and risk for our customers. Our risk management policies allow us to use financial instruments for trading purposes and to hedge risks, but not for speculative trading. We have a management-level Energy Risk Management Committee that monitors risks in accordance with our risk management policies.
We purchase and sell financial options for natural gas in all three states for our gas purchase portfolios.

Because the gains or losses of financial derivatives under the North Carolina and South Carolina hedging plans utilized in the regulated utility segment are recovered through our rates, subject to regulatory commission review, current period changes in the assets and liabilities from these risk management activities are recorded as a component of gas costs in amounts due customers in accordance with Statement 71. Accordingly, there is no earnings impact to the regulated utility segment as a result of the use of these financial derivatives. In Tennessee, the cost of the options and all other gas costs incurred are components of and are recovered under the guidelines of the Tennessee Incentive Plan approved by the Tennessee Regulatory Authority (TRA). As of July 31, 2005 and October 31, 2004, the total fair value of options included in the condensed consolidated balance sheets was $9.6 million and $13.2 million, respectively.

10. In connection with the sale in January 2004 of our propane interests, we received 37,244 common units of Energy Transfer Partners, LP, which were recorded at market value in Marketable securities in the condensed consolidated balance sheets. During the three months ended April 30, 2005, we sold these units for $2.4 million and recorded a pre-tax gain of $1.5 million in the condensed consolidated statements of operations for the nine and twelve months ended July 31, 2005.

11. Prepayments decreased from $38.7 million as of October 31, 2004, to $27.2 million as of July 31, 2005, primarily due to a decrease in prepaid gas costs. Under asset management agreements, prepaid gas costs during the summer months represent purchases of gas that is not available for sale, and therefore not recorded in inventory, until November 1, the beginning of the winter period.

12. Notes payable decreased from $109.5 million as of October 31, 2004, to $84 million as of July 31, 2005, as cash flows during the period resulted in lower outstanding borrowings under our short-term lines of credit as of July 31, 2005.

13. In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 153, Exchanges of Nonmonetary Assets (Statement 153). The provisions of Statement 153 are effective for nonmonetary asset exchanges that occur in our fiscal quarter beginning August 1, 2005. We believe the adoption of Statement 153 will not have a material effect on our financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment (Statement 123R). Statement 123R requires entities to adopt the fair value method of accounting for stock-based plans. The fair value method would require the amortization of the fair value of stock-based compensation as determined at the date of grant over the related vesting period. Under Statement 123R, most employee stock purchase plans that offer a discount of greater than 5% will be considered compensatory. Statement 123R is effective for us in our fiscal quarter beginning November 1, 2005. We intend to amend our employee stock purchase plan to lower the discount rate from 10% to 5%.

In March 2005, the FASB issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47) to clarify the term conditional asset retirement as used in SFAS 143, Accounting for Asset Retirement Obligations. FIN 47 requires that a liability be recognized for the fair value of a conditional asset retirement obligation when incurred, if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation would be factored into the measurement of the liability when sufficient information exists. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. Accordingly, we will adopt FIN 47 no later than our fourth fiscal quarter in 2006. We are currently assessing the impact FIN 47 may have on our balance sheet; however, we believe the adoption of FIN 47 will not have a material impact on our results of operations or cash flows.

In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections (Statement 154),

a replacement of Accounting Principles Board (APB) Opinion No. 20 and SFAS No. 3. Statement 154 applies to all voluntary changes in accounting principle and changes the requirements for accounting for and reporting of a change in accounting principle. Retrospective application to prior periods financial statements of the change in accounting principle is required unless it is impracticable. Statement 154 is effective for fiscal years beginning after December 15, 2005, with earlier application permitted in fiscal years beginning after June 1, 2005.

In July 2005, the FASB issued FASB Staff Position APB 18-1, Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence (FSP APB 18-1). The provisions of FSP APB 18-1 are effective in our fiscal quarter beginning August 1, 2005. We believe the adoption of FSP APB 18-1 will not have a material effect on our financial position or results of operations.

14. On May 12, 2005, we sold our corporate office building located in Charlotte, North Carolina, for $6.7 million, net of a real estate commission of $226,000 paid to a commercial real estate company affiliated with a member of our Board of Directors. Under the terms of the purchase and sale agreement, we have leased back the building while our new office space, which is expected to be ready for occupancy in November 2005, is under construction. The total amount of rent for the rental period is estimated to be $.6 million. In accordance with utility plant accounting, we recorded the disposition of the land as a pre-tax gain of $1.7 million in Other Income (Expense) in the condensed consolidated statements of operations and a loss of $1.8 million on the disposition of the building as a charge to Accumulated Depreciation in the condensed consolidated balance sheets, based on the sales price allocation from an independent third party.

15. We have reclassified certain information in the condensed consolidated statements of cash flows for the three, nine and twelve months ended July 31, 2004, to conform with the 2005 presentation. Such reclassifications from operating cash flow to investing cash flow outflow consist primarily of restricted cash ($5.8 million for the three and nine months and $5.9 million for the twelve months ended July 31, 2004) and the change in EasternNC s capital bond fund receivable ($4.9 million, $5.9 million and $8.5 million for the three, nine and twelve months ended July 31, 2004, respectively).

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Overview

Piedmont Natural Gas Company is an energy services company primarily engaged in the distribution of natural gas to residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee. We also have equity method investments in joint venture, energy-related businesses. Our operations are comprised of two business segments.

The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. This segment is regulated by three state regulatory commissions that approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. Factors critical to the success of the regulated utility include a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in rates charged to customers.

The non-utility activities segment consists of our equity method investments in joint venture, energy-related businesses that are involved in unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. We invest in joint ventures that are aligned with our business strategies to complement or supplement income from utility operations. We continually monitor performance and rates of return of these ventures against expectations.

Weather conditions directly influence the volumes of natural gas delivered by the regulated utility. Significant portions of our revenues are generated during the winter season. During warm winters or unevenly cold winters, heating customers may significantly reduce their consumption of natural gas. Although we have weather normalization adjustment mechanisms (WNA) that are designed to protect a portion of our revenues

against warmer-than-normal weather, deviations from normal weather can affect our financial performance and liquidity. The WNA also serves to offset the impact of colder-than-normal weather by reducing the amounts we can charge our customers.

In the past few years, there have been significant increases in the wholesale cost of natural gas. The relationship between supply and demand has the greatest impact on wholesale gas prices. Although we believe there are sufficient supplies of natural gas to meet our customers needs, price increases could shift our customers preference away from natural gas and toward competing energy sources, particularly in the industrial market. Price increases could also affect the consumption levels of our customers or make it more difficult for them to pay their bills. We expect that the wholesale price of natural gas will remain high and volatile until natural gas supply and demand are better balanced.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005, the first major energy legislation passed by Congress in 13 years. We believe this legislation is the first step towards addressing our nation s energy issues. Key provisions of the Act include:

Encouraging the development of additional supplies by:

- streamlining the permitting process,
- increasing royalty incentives for Outer Continental Shelf (OCS) production,
- authorizing an inventory of the OCS reserves by the Department of the Interior and
- encouraging capital spending by recognizing shorter depreciation periods.

Promoting energy efficiencies and conservation by:

- providing tax incentives to homeowners, contractors and businesses and
- encouraging and promoting power generation from energy sources other than natural gas.

It is too early to identify the impact of this legislation on us.

Although we have been operating in a relatively low-interest-rate environment for both short- and long-term debt financing during the past few years, the Federal Reserve recently increased the federal funds rate to 3.5%, the highest level in nearly four years. This change could result in an increase in rates on our short-term borrowings. A rise in interest rates could negatively affect our earnings. The level of our short-term borrowings can vary significantly due to changes in the wholesale prices of natural gas that could subject us to short-term interest rate risks.

Part of our strategic plan is to effectively manage our gas distribution operations through innovative rate and regulatory initiatives, with a continuing focus on controlling operating costs and implementing new technologies to achieve this end. We are working to enhance the value and growth of our utility assets by good management of capital spending, both for improvements for current customers and the pursuit of customer growth opportunities in our service areas. We strive for excellent customer service by investing in systems, processes and people. We will continue to work with our state regulators to maintain fair rates of return and balance the interests of our customers and shareholders.

Our strategic plan includes a focus on maintaining a debt-to-capitalization ratio within a range of 45 to 50%. We will continue to stress the importance of maintaining a strong balance sheet and investment-grade credit ratings to support our operating and investment needs. We continuously monitor our level of short-term borrowings to secure short-term bank lines that meet our short-term operating needs.

Results of Operations

We will discuss the results of operations for the three, nine and twelve months ended July 31, 2005, compared

with similar periods in 2004. Operating results for the three months ended July 31, 2005 and 2004, the nine months ended July 31, 2005 and 2004, and the twelve months ended July 31, 2005, reflect the full effect of the acquisitions of NCNG and an equity interest in EasternNC on September 30, 2003.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. We have a WNA in all three states that partially offsets the impact of unusually cold or warm weather on bills rendered during the months of November through March for weather-sensitive customers. In North Carolina and Tennessee, adjustments are made directly to the customer s bill. In South Carolina, the adjustments are calculated at the individual customer level and recorded in a deferred account (regulatory asset or liability) for subsequent collection from or refund to all customers in the class. The WNA formula calculates the actual weather variance from normal, using 30 years of history, which results in an increase in revenues when weather is warmer than normal and a decrease in revenues when weather is colder than normal. The gas cost portion of our costs is recoverable through purchased gas adjustment (PGA) procedures and is not affected by the WNA.

Operating Revenues

Operating revenues were $232.9 million and $214.7 million for the three months ended July 31, 2005 and 2004, respectively. Operating revenues in 2005 increased $18.2 million compared with the similar prior period primarily due to the following increases.

- $9.4 million from increased commodity gas costs passed through to customers.

- $7.5 million from secondary market transactions. Secondary market transactions consist of off-system sales and capacity release arrangements.

- $2.4 million in non-volumetric amounts billed to customers under tariffs and contract provisions.

These increases were partially offset by a decrease of $2.7 million due to a decrease in volumes delivered of .8 million dekatherms.

Operating revenues were $1,421.5 million and $1,315.9 million for the nine months ended July 31, 2005 and 2004, respectively. Operating revenues in 2005 increased $105.6 million compared with the similar prior period primarily due to the following increases.

- $94 million from increased commodity gas costs passed through to customers.

- $7.4 million from the WNA due to surcharges to customers of $7.2 million in 2005 compared with credits of $.2 million in 2004. Weather for the nine months ended July 31, 2005, was 4% warmer than normal compared with normal for the same period in 2004.

- $14 million from secondary market transactions.

These increases were partially offset by a decrease of $6.4 million due to a decrease in volumes delivered of 1 million dekatherms.

Operating revenues were $1,635.3 million and $1,495.4 million for the twelve months ended July 31, 2005 and 2004, respectively. Operating revenues in 2005 increased $139.9 million compared with the similar prior period primarily due to the following increases.

- $52.5 million from increased commodity gas costs passed through to customers.

- $46.7 million from an increase in volumes delivered of 7.8 million dekatherms primarily from NCNG and EasternNC, which included twelve months activity for 2005 and only ten months activity for 2004.

$32.3 million from secondary market transactions.

$9.1 million from the WNA due to surcharges to customers of $9.5 million in 2005 compared with surcharges of $.4 million in 2004. Weather for the twelve months ended July 31, 2005, was 7 % warmer than normal compared with normal for the same period in 2004.

Cost of Gas

Cost of gas was $156.3 million and $145 million for the three months ended July 31, 2005 and 2004, respectively. Cost of gas in 2005 increased $11.3 million compared with the similar prior period primarily due to the following increases.

$9.4 million from increased commodity gas costs.

$6.2 million from secondary market transactions.

These increases were partially offset by a decrease of $2 million due to a decrease in volumes delivered.

Cost of gas was $1,001.6 million and $903.9 million for the nine months ended July 31, 2005 and 2004, respectively. Cost of gas in 2005 increased $97.7 million compared with the similar prior period primarily due to the following increases.

$94 million from increased commodity gas costs.

$13 million from secondary market transactions.

These increases were partially offset by a decrease of $4.7 million due to a decrease in volumes delivered.

Cost of gas was $1,139.1 million and $1,021.4 million for the twelve months ended July 31, 2005 and 2004, respectively. Cost of gas in 2005 increased $117.7 million compared with the similar prior period primarily due to the following increases.

$52.5 million from increased commodity gas costs.

$32.8 million from an increase in volumes delivered of 7.8 million dekatherms primarily from NCNG and EasternNC.

$30 million from secondary market transactions.

Under PGA procedures in all three states, we revise rates periodically without formal rate proceedings to reflect changes in the wholesale cost of gas. 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 added to or deducted from cost of gas and included in Amounts due from customers or Amounts due to customers in the condensed consolidated balance sheets. In North Carolina and South Carolina, recoveries of gas costs are subject to annual gas cost recovery proceedings to determine the prudence of our gas purchases. We have been found prudent in all such past proceedings.

Margin

Margin was $76.6 million and $69.7 million for the three months ended July 31, 2005 and 2004, respectively. Margin in 2005 increased $6.9 million compared with the similar prior period primarily due to increased consumption in the residential, commercial and industrial customer classes because of colder weather in May 2005 and increases in the large-volume market and the secondary market.

Margin was $419.9 million and $412 million for the nine months ended July 31, 2005 and 2004, respectively. Margin in 2005 increased $7.9 million compared with the similar prior period primarily due to growth in the residential and commercial customer base, partially offset by decreased consumption because of warmer weather and continued customer conservation.

Margin was $496.2 million and $474 million for the twelve months ended July 31, 2005 and 2004, respectively. Margin in 2005 increased $22.2 million compared with the similar prior period primarily from NCNG and EasternNC operations and growth in the residential and commercial customer base, partially offset by decreased consumption because of warmer weather and continued customer conservation.

Operations and Maintenance Expenses

Operations and maintenance expenses were $50.2 million and $47.8 million for the three months ended July 31, 2005 and 2004, respectively. Operations and maintenance expenses in 2005 increased $2.4 million compared with the similar prior period due to the following increases.

- $1.4 million in employee benefits expense primarily due to pension and postretirement health care and health insurance costs.
- $.9 million in payroll costs due to an increase in the accrued long-term incentive plan liability to reflect a higher stock price on which the accrual is based and an additional award effective November 1, 2004.
- $.7 million in the provision for uncollectibles.

Operations and maintenance expenses were $152.8 million and $148 million for the nine months ended July 31, 2005 and 2004, respectively. Operations and maintenance expenses in 2005 increased $4.8 million compared with the similar prior period due to the following increases.

- $1.1 million in payroll costs due to an increase in the accrued vacation pay liability resulting in part to increased vacation benefits effective January 1, 2005.
- $2.8 million in employee benefits expense primarily due to pension and postretirement health care and health insurance costs.
- $1.7 million in payroll costs due to an increase in the accrued long-term incentive plan liability to reflect a higher stock price on which the accrual is based and an additional award effective November 1, 2004.
- $.9 million in utilities primarily due to increased telecommunications costs.
- $.7 million in outside labor primarily due to costs of data-center sourcing.

These increases were partially offset by the following decreases.

- $.8 million in the provision for uncollectibles primarily due to improved collection results, including recoveries of previously written-off accounts.
- $1 million in other corporate expense due primarily to lower bank fees, lower shareholder expenses, sales tax expense and deferral of Nashville franchise fee that was expensed in an earlier period.

Operations and maintenance expenses were $205.1 million and $186.1 million for the twelve months ended July 31, 2005 and 2004, respectively. Operations and maintenance expenses in 2005 increased $19 million compared with the similar prior period primarily due to the following increases.

- $6.3 million in payroll costs primarily due to accruals for the long-term and short-term incentive plans, merit pay increases and the inclusion of NCNG employees for twelve months in the 2005 period compared with only ten months in the 2004 period.

$2.9 million in outside labor primarily due to NCNG operations, costs of data-center sourcing and the deferral to a regulatory asset in the prior period which reversed certain NCNG integration costs that were expensed in an earlier period.

$2.6 million in employee benefits expense primarily due to pension and postretirement health care and health insurance costs.

$2.3 million due to accrual of the projected benefit obligation for a retirement plan for certain current and former members of the Board of Directors.

$2.1 million in other corporate expenses primarily due to amortization of NCNG integration costs and the deferral in 2003 to a regulatory asset of EasternNC s operations and maintenance costs that had been expensed prior to September 30, 2003.

$1.4 million in consulting fees primarily due to the deferral to a regulatory asset in the prior period of certain NCNG integration costs.

$1.3 million in utilities primarily due to increased telecommunications costs.

$.7 million in transportation expenses primarily due to an increase in fuel costs and the inclusion of NCNG for twelve months in the 2005 period compared with only ten months in the 2004 period.

$.7 million in payroll costs due to an increase in the accrued vacation pay liability resulting in part to increased vacation benefits effective January 1, 2005.

These increases were partially offset by a decrease in the provision for uncollectibles of $2.9 million, primarily due to improved collection results, including recoveries of previously written-off accounts.

Depreciation

Depreciation expense was $21.5 million and $20.9 million for the three months ended July 31, 2005 and 2004, respectively, $63.3 million and $61.5 million for the nine months ended July 31, 2005 and 2004, respectively, and $84 million and $78.8 million for the twelve months ended July 31, 2005 and 2004, respectively. Depreciation expense for the current periods increased over similar prior periods primarily due to increases in plant in service, including a full twelve months of depreciation expense on plant acquired from NCNG for the 2005 period compared with ten months for the similar 2004 period. Due to the continued growth in our service areas and the related capital expansion, we anticipate that depreciation expense will continue to increase.

General Taxes

General taxes were $7.7 million and $7 million for the three months ended July 31, 2005 and 2004, respectively. General taxes in 2005 increased $.7 million compared with the similar prior period primarily due to the following increases.

$.3 million in payroll taxes.

$.2 million in property taxes based on increases in tax rates and assessed valuations.

General taxes were $23.4 million and $20.4 million for the nine months ended July 31, 2005 and 2004, respectively. General taxes in 2005 increased $3 million compared with the similar prior period primarily due to the following increases.

$1.8 million in Tennessee property taxes as the expense in 2004 reflected the impact of a favorable court ruling that reduced assessed property values and the estimated tax accruals for prior periods.

$.6 million in payroll taxes.

$.3 million in property taxes.

General taxes were $30 million and $26 million for the twelve months ended July 31, 2005 and 2004, respectively. General taxes increased $4 million compared with the similar prior period primarily due to the following increases.

- $1.8 million in Tennessee property taxes noted above.
- $1.2 million in other property taxes, including $.5 million from NCNG operations.
- $.7 million in payroll taxes.
- $.3 million in Tennessee gross receipts taxes.

Other Income (Expense)

Income from equity method investments was $4.1 million and $4 million for the three months ended July 31, 2005 and 2004, respectively.

Income from equity method investments was $24.5 million and $25.4 million for the nine months ended July 31, 2005 and 2004, respectively. Income from equity method investments decreased $.9 million compared with the similar prior period primarily due to the absence of earnings from propane activities due to the sale of our propane interests in January 2004, partially offset by an increase in earnings from SouthStar of $1.2 million.

Income from equity method investments was $26.5 million and $27.3 million for the twelve months ended July 31, 2005 and 2004, respectively. Income from equity method investments in 2005 decreased $.8 million compared with the similar prior period primarily due to the absence of earnings from propane activities, partially offset by increases in earnings from SouthStar of $.6 million, Cardinal of $.2 million and Pine Needle of $.2 million.

The gain on sale of equity method investments resulted from the sale of our propane interests in January 2004.

The gain on sale of marketable securities resulted from the sale in February 2005 of 37,244 common units of Energy Transfer Partners, L.P., which we acquired in connection with the sale of our propane interests. Total proceeds from the sale were $2.4 million and resulted in a pre-tax gain of $1.5 million.

The equity portion of the allowance for funds used during construction (AFUDC) for the three, nine and twelve months ended July 31, 2005, decreased slightly compared with similar prior periods. AFUDC is allocated between equity and debt based on the ratio of construction work in progress to average short-term borrowings.

Non-operating income is comprised of non-regulated merchandising and service work, subsidiary operations, interest income and other miscellaneous income. Non-operating income in the 2005 periods includes a pre-tax gain on the sale of the corporate office land of $1.7 million. For further information on the sale, see Note 14 to the condensed consolidated financial statements. All other non-operating income and fluctuations in non-operating income are not significant.

Charitable contributions for the twelve months ended July 31, 2005, increased $7.6 million compared with the similar prior period primarily due to the initial funding of $7 million to the Piedmont Natural Gas Foundation established in October 2004.

Utility Interest Charges

Utility interest charges were $11.1 million and $12.7 million for the three months ended July 31, 2005 and 2004, respectively. Utility interest charges in 2005 decreased $1.6 million compared with the similar prior period primarily due to the following decreases.

- $.9 million in interest on amounts due to/from customers due to higher average net receivables in the current period compared with the similar prior period.

- $.8 million due to interest incurred in the 2004 period in connection with the audit of our federal income tax return for the year ended October 31, 2001.

Utility interest charges were $34.1 million and $36.2 million for the nine months ended July 31, 2005 and 2004, respectively. Utility interest charges in 2005 decreased $2.1 million compared with the similar prior period primarily due to the following decreases.

- $2.4 million in interest on amounts due to/from customers due to higher average net receivables in the current period compared with the similar prior period.

- $.9 million in interest on short-term debt due to the repayment of the commercial paper program in December 2003 that we utilized to temporarily finance the NCNG acquisition.

- $.8 million in interest in connection with the audit of our federal income tax return.

- $.6 million due to an increase in AFUDC allocated to debt.

These decreases were partially offset by the following increases.

- $1.2 million in interest on long-term debt due to higher balances outstanding as a result of the permanent financing of the NCNG acquisition.

- $.9 million in interest on short-term debt due to higher amounts of debt outstanding at higher interest rates.

- $.4 million in interest on the North Carolina allocated portion of current deferred income taxes for revenues and gas cost items as required by the NCUC.

Utility interest charges were $45.6 million and $46.5 million for the twelve months ended July 31, 2005 and 2004, respectively. Utility interest charges in 2005 decreased $.9 million compared with the similar prior period primarily due to the following decreases.

- $.8 million in interest in connection with the audit of our federal income tax return.

- $3.1 million in interest on amounts due to/from customers due to higher average net receivables in the current period compared with the similar prior period.

- $1.9 million in interest on short-term debt due to the repayment of commercial paper in December 2003.

- $.8 million due to an increase in AFUDC allocated to debt.

These decreases were partially offset by the following increases.

- $3.8 million in interest on long-term debt due to higher balances outstanding, including amounts due to the permanent financing of the NCNG acquisition.

- $1 million in interest on short-term debt due to higher amounts of debt outstanding at higher interest rates.

- $.5 million in interest on the North Carolina allocated portion of current deferred income taxes for revenues and gas cost items.

Our Business

Piedmont Natural Gas Company, Inc., which began operations in 1951, is an energy services company primarily engaged in the distribution of natural gas to 960,000 residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee, including 60,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage, intrastate natural gas transportation and regulated natural gas distribution. We also sell residential and commercial gas appliances in Tennessee.

Effective at the close of business on September 30, 2003, we purchased 100% of the common stock of NCNG from Progress Energy, Inc. (Progress), for $417.5 million in cash plus $32.4 million for estimated working capital. We paid an additional $.3 million for actual working capital in the second quarter ended April 30, 2004. At the time of the acquisition, NCNG, a regulated natural gas distribution company, served 176,000 customers in eastern North Carolina, including 57,000 customers served by four municipalities who were wholesale customers of NCNG. NCNG was merged into Piedmont immediately following the closing.

We also purchased for $7.5 million in cash Progress equity interest in EasternNC. EasternNC is a regulated utility that has a certificate of public convenience and necessity from the NCUC to provide natural gas service to 14 counties in eastern North Carolina that previously were not served with natural gas. Progress equity interest in EasternNC consisted of 50% of EasternNC s outstanding common stock and 100% of EasternNC s outstanding preferred stock.

We have two reportable business segments, regulated utility and non-utility activities. For further information on business segments, see Note 7 to the condensed consolidated financial statements.

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

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

We continually assess the nature of our business and explore alternatives to traditional utility regulation. Non-traditional ratemaking initiatives and market-based pricing of products and services provide additional challenges and opportunities for us. For further information, see Results of Operations above and Note 9 to the condensed consolidated financial statements.

We invest in joint ventures to complement or supplement income from utility operations. If an opportunity aligns with our overall business strategies, we analyze and evaluate the project with a major factor being a projected rate of return greater than the returns allowed in our utility operations, due to the higher risk of such projects. We make only those investments that are approved by our Board of Directors. We participate in the governance of the venture by having a management representative on the governing board of the venture. We monitor actual performance and rates of return against expectations and make periodic reports to the Board. Decisions regarding exiting joint ventures are based on many factors, including performance results and continued alignment with our business strategies.

Financial Condition and Liquidity

We believe we have access to adequate resources to meet our needs for working capital, construction expenditures, debt redemptions and dividend payments. These resources include net cash flows from operating activities, access to capital markets, cash generated from our investments in joint ventures and bank lines of credit.

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 such factors as weather, natural gas prices, collections from customers, natural gas purchases and gas inventory storage activity. We rely on operating cash flows and short-term bank borrowings to meet seasonal working capital needs. During our first and second quarters, we generally have positive cash flows from the sale of flowing gas and gas in storage and the collection of amounts billed to customers. This cash is used to reduce short-term debt to zero during much of the second and third quarters. Most of our annual earnings are realized in the winter period, which is the first five months of our fiscal year. Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases for storage and decreases in receipts from customers.

Net cash provided by (used in) operating activities was $(33.4) million and $(56.4) million for the three months ended July 31, 2005 and 2004, respectively, $164.9 million and $200.6 million for the nine months ended July 31, 2005 and 2004, respectively, and $122 million and $172.9 million for the twelve months ended July 31, 2005 and 2004, respectively. The primary factor that impacts our cash flows from operations is weather. Warmer weather can lead to lower total margin 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 consumption. Temperatures above normal can lead to reduced operating cash flows, thereby increasing the need for short-term borrowings to meet current cash requirements. Volumes of natural gas sold to both residential and commercial customers are weather-sensitive.

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 minimal based on our receipt of the products and services prior to payment and the availability of other marketers of natural gas to meet our supply needs if necessary.

The regulated utility faces competition in the residential and commercial customer markets based on customer preferences for natural gas compared with other energy products, such as electricity and propane. The most significant product competition is with electricity for space heating, water heating and cooking. 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 have the capability of burning a fuel other than natural gas, fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on price. The relationship between supply and demand has the greatest impact on the price of natural gas. With the imbalance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between supply and demand and the policies of foreign and domestic governments. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

Cash Flows from Investing Activities. Net cash used in investing activities was $44.3 million and $34.7 million for the three months ended July 31, 2005 and 2004, respectively, $84.8 million and $17.2 million for the nine months ended July 31, 2005 and 2004, respectively, and $107.3 million and $485.9 million for the twelve months ended July 31, 2005 and 2004, respectively. The net cash used in investing activities for the three, nine and twelve months ended July 31, 2005, and the three and nine months ended July 31, 2004, was primarily for utility construction expenditures. Net cash used in investing activities for the twelve months ended July 31, 2004, was primarily for the acquisitions of NCNG and EasternNC and utility capital expenditures. As expenditures are made in EasternNC s service territory, reimbursement requests are made to the State of North Carolina under orders issued by the NCUC granting EasternNC a total of $188.3 million of bond funds. Such funds are available to pay for the uneconomic portion of the construction of a natural gas distribution infrastructure in the eastern part of the state. For further information about the bond fund, see Gas Supply and Regulatory Proceedings below.

We have a substantial capital expansion program for construction of distribution facilities, purchase of equipment and other general improvements. This program primarily supports the growth in our customer base. We have budgeted $157.4 million for utility construction expenditures for fiscal 2005. Due to projected growth in our service areas, significant utility construction expenditures are expected to continue and are a part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years.

On May 12, 2005, we sold our corporate office building located in Charlotte, North Carolina for $6.7 million, net of expenses, and realized a pre-tax gain of $1.7 million on the sale of the land. For further information about the sale, see Note 14 to the condensed consolidated financial statements. We have negotiated a ten-year lease with renewable options for space in a building that is currently under construction and is expected to be ready for occupancy in November 2005. The lease payments for the ten-year term range from $3 million to $3.4 million annually. We have leased our current office building from the new owner pending occupancy of the new office space.

Subject to various governmental approvals, we intend to jointly develop an underground interstate natural gas storage facility in West Virginia with Columbia Hardy Corporation, a subsidiary of Columbia Gas Transmission Corporation. Total project capital expenditures are estimated at $122 million over a five-year period, of which our share is $61 million. On August 5, 2005, the FERC staff issued an environmental assessment concluding the project would not significantly affect the quality of the environment.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was $63.5 million and $14 million for the three months ended July 31, 2005 and 2004, respectively, $(80.1) million and $(190.2) million for the nine months ended July 31, 2005 and 2004, respectively, and $(13.3) million and $309.8 million for the twelve months ended July 31, 2005 and 2004, respectively. Funds are generally provided from bank borrowings and the issuance of Common Stock through dividend reinvestment and employee stock plans, net of repurchases under the common stock repurchase program. We sell Common Stock and long-term debt

to cover cash requirements when market and other conditions favor such long-term financing. As of July 31, 2005, our current assets were $339 million and our current liabilities were $322.8 million.
Under committed bank lines of credit totaling $250 million, outstanding short-term borrowings during the three months and nine months ended July 31, 2005, are detailed below. As of July 31, 2005, we had additional uncommitted lines of credit totaling $98 million on a no fee and as needed, if available, basis.

	Three Months		Nine Months	
In thousands	High	Low	High	Low
Outstanding short-term borrowings	$ 112,000	$	$ 229,500	$
Interest rates	3.62%	3.36%	3.62%	2.11%

The level of short-term borrowings can vary significantly due to changes in the wholesale prices of natural gas and to increased purchases of natural gas supplies to serve customer demand and to refill storage. Short-term debt may increase when wholesale prices for natural gas increase because we must pay suppliers for the gas before we recover our costs from customers through their monthly bills. Gas prices could continue to increase and fluctuate. If wholesale gas prices remain high, we may incur more short-term debt to pay for natural gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their gas bills on a timely basis.
Under the Common Stock Open Market Purchase Program, which began on September 1, 2004, we utilize a broker to repurchase shares on the open market. Such shares are then cancelled and become authorized but unissued shares available for issuance to the Long-Term Incentive Plan and to dividend reinvestment and stock purchase plans.
We have paid quarterly dividends on our Common Stock since 1956. The amount of cash dividends that may be paid is restricted by provisions contained in certain note agreements under which long-term debt was issued. As of July 31, 2005, none of our retained earnings were restricted.
As of July 31, 2005, our capitalization consisted of 41% in long-term debt and 59% in common equity. Our long-term targeted capitalization ratio is 45-50% in long-term debt and 50-55% in common equity.
As of July 31, 2005, all of our long-term debt was unsecured. Our long-term debt is rated A by Standard & Poor s Ratings Services and A3 by Moody s Investors. Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings.
We are subject to default provisions related to our long-term debt and short-term bank lines of credit. Failure to satisfy any of the default provisions would result in total outstanding issues of debt becoming due. There are cross-default provisions in all our debt agreements. As of July 31, 2005, we are in compliance with all default provisions.

Estimated Future Contractual Obligations

During the three months ended July 31, 2005, there were no material changes to our estimated future contractual obligations outside the ordinary course of business.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases that are discussed in Note 7 to the

consolidated financial statements in our Form 10-K/A for the year ended October 31, 2004.

Critical Accounting Policies and Estimates

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

Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or a different estimate that could have been used would have had a material impact on our financial condition or results of operations. We consider regulatory accounting, revenue recognition, goodwill and pension and postretirement benefits to be our critical accounting estimates. Management is responsible for the selection of the critical accounting estimates presented in our Form 10-K for the year ended October 31, 2004, in Management s Discussion and Analysis of Financial Condition and Results of Operations. Management has discussed these critical accounting estimates with the Audit Committee of the Board of Directors. There have been no changes in our critical accounting policies and estimates since October 31, 2004.

Gas Supply and Regulatory Proceedings

In 1998, 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 the state. EasternNC has been granted a certificate by the NCUC to provide natural gas service to 14 unserved counties in the eastern-most part of North Carolina. These counties historically have not been able to obtain gas service because of the relatively sparse population of the counties and the resulting uneconomic feasibility of providing service. The NCUC has issued orders approving $188.3 million of the bond fund to EasternNC for construction of natural gas facilities in the 14 counties. During the period November 1, 2004 through July 31, 2005, we filed for reimbursement of $26.3 million from the bond fund and received $23.3 million. As of July 31, 2005, there was $22.5 million remaining of the bond funds allocated to EasternNC. As of July 31, 2005 and October 31, 2004, we had receivables of $6.6 million and $3.5 million, respectively, from the bond fund recorded in Receivables in the condensed consolidated balance sheets. In accordance with NCUC orders, we must contribute funding to the project that is not subject to bond reimbursement.

On February 1, 2005, we entered into a Stock Purchase Agreement with the other owner of EasternNC under which they will sell all of their shares of common stock of, and assign all of their rights and obligations in, EasternNC to Piedmont. Closing of the transaction is scheduled to occur three business days after all of the following conditions are met:

- Approval by Piedmont s Board of Directors.
- Consideration of $1.00 paid by Piedmont to the other owner.
- Approval of the acquisition and merger by the NCUC.
- Approval by the NCUC to roll-in and combine the rate structure of EasternNC into Piedmont s rate structure on terms and conditions acceptable to Piedmont.

On June 23, 2005, a hearing for the acquisition and merger was held with the NCUC and interested parties. On August 22, the NCUC issued an order approving the acquisition and merger and determined that it was appropriate for the operations, revenues, expenses and rate base of EasternNC to be integrated into Piedmont s larger system. The precise structure and specifics of such a roll-in will be addressed in the pending general rate case proceeding discussed in the following paragraph.

On April 1, 2005, we filed a general rate case application with the NCUC requesting a consolidation of the respective rate bases, revenues and expenses of Piedmont, our NCNG division and EasternNC. In addition to a unified and uniform rate structure for all customers served by us in North Carolina, the application requested a general restructuring and increase in rates and charges for customers to produce an overall annual increase in margin of $36.7 million, a consolidation and/or amortization of certain deferred accounts, changes to cost allocations and rate design including an innovative conservation tariff mechanism that decouples margin recovery from residential and commercial customer consumption, changes and unification of existing service regulations and tariffs, implementation of a collection and contribution mechanism and common depreciation rates for plant. New rates are proposed to be effective November 1, 2005.

On August 31, 2005, a stipulation was filed in this proceeding resolving all issues and providing a margin increase of $20.2 million. The stipulation was supported by the Public Staff of the NCUC, the Carolina Utility Customers Association, Inc., the Department of Defense and various municipalities. Only the State Attorney General s Office opposed the stipulation. A hearing was held September 6, 2005, before the NCUC to address the opposition. The stipulation is now pending before the NCUC.

On February 16, 2005, the Natural Gas Rate Stabilization Act of 2005 became effective in South Carolina. The law provides electing natural gas utilities, including Piedmont, with a mechanism for the regular, periodic and more frequent (annual) adjustment of rates which is intended to: (1) encourage investment by natural gas utilities, (2) enhance economic development efforts, (3) reduce the cost of rate adjustment proceedings and (4) result in smaller but more frequent rate changes for customers. If the utility elects to operate under the Act, the annual filing will provide that the utility s rate of return on equity will remain within a 50-basis points band above or below the current allowed rate of return on equity. On April 26, 2005, we filed an election with the PSCSC to adopt this new mechanism.

On June 15, 2005, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2005, along with revenue deficiency calculations and proposed changes in our tariff rates. We requested an increase in annual revenues of $4.6 million, including a gas cost adjustment of $1.4 million. After receiving comments from any interested party and a review by the Office of Regulatory Staff, the PSCSC will issue an initial order on or before October 15, 2005, and new rates will be effective on November 1, 2005.

Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets (Statement 153). The provisions of Statement 153 are effective for nonmonetary asset exchanges that occur in our fiscal quarter beginning August 1, 2005. We believe the adoption of Statement 153 will not have a material effect on our financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment (Statement 123R). Statement 123R requires entities to adopt the fair value method of accounting for stock-based plans. The fair value method would require the amortization of the fair value of stock-based compensation as determined at the date

of grant over the related vesting period. Under Statement 123R, most employee stock purchase plans that offer a discount of greater than 5% will be considered compensatory. Statement 123R is effective for us in our fiscal quarter beginning November 1, 2005. We intend to amend our employee stock purchase plan to lower the discount rate from 10% to 5%.

In March 2005, the FASB issued Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47) to clarify the term conditional asset retirement as used in SFAS 143, Accounting for Asset Retirement Obligations. FIN 47 requires that a liability be recognized for the fair value of a conditional asset retirement obligation when incurred, if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation would be factored into the measurement of the liability when sufficient information exists. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. Accordingly, we will adopt FIN 47 no later than our fourth fiscal quarter in 2006. We are currently assessing the impact FIN 47 may have on our balance sheet; however, we believe the adoption of FIN 47 will not have a material impact on our results of operations or cash flows.

In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections (Statement 154), a replacement of APB Opinion No. 20 and SFAS No. 3. Statement 154 applies to all voluntary changes in accounting principle and changes the requirements for accounting for and reporting of a change in accounting principle. Retrospective application to prior periods financial statements of the change in accounting principle is required unless it is impracticable. Statement 154 is effective for fiscal years beginning after December 15, 2005, with earlier application permitted in fiscal years beginning after June 1, 2005.

In July 2005, the FASB issued FASB Staff Position APB 18-1, Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence (FSP APB 18-1). The provisions of FSP APB 18-1 are effective in our fiscal quarter beginning August 1, 2005. We believe the adoption of FSP APB 18-1 will not have a material effect on our financial position or results of operations.

Forward-Looking Statements

Documents we file with the SEC may contain forward-looking statements. In addition, our senior management and other authorized spokespersons may make forward-looking statements in print or orally to analysts, investors, the media and others. Forward-looking statements concern, among others, plans, objectives, proposed capital expenditures and future events or performance. These statements reflect our current expectations and involve a number of risks and uncertainties. Although we believe that our expectations are based on reasonable assumptions, actual results may differ materially from those suggested by the forward-looking statements. Important factors that could cause actual results to differ include:

Regulatory issues, including those that affect allowed rates of return, terms and conditions of service, rate structures and financings. We monitor our effectiveness in achieving the allowed rates of return and initiate rate proceedings or operating changes as needed. In addition, we purchase natural gas transportation and storage services from interstate and intrastate pipeline companies whose rates and services are also regulated.

Residential, commercial and industrial growth in our service areas. The ability to grow our customer base and the pace of that growth are impacted by general business and economic conditions and the overall strength of the economy in our service areas and the country, including such factors as interest rates, inflation, fluctuations in the capital markets and increases in the wholesale cost of natural gas.

Deregulation, regulatory restructuring and competition in the energy industry. We face competition from electric companies and energy marketing and trading companies and we expect this highly

competitive environment to continue.

The potential loss of large-volume industrial customers to alternate fuels or to bypass or the shift by such customers to special competitive contracts at lower per-unit margins.

Regulatory issues, customer growth, deregulation, economic and capital market conditions, the cost and availability of natural gas and weather conditions can impact our ability to meet internal performance goals.

The capital-intensive nature of our business. In order to maintain growth, we must add to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining governmental approvals, development project delays or changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project. Our internally generated cash flows are not adequate to finance the full cost of this construction. As a result, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations.

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

Impact of the Energy Policy Act of 2005. Key components of the bill include provisions that encourage fuel diversity in the generation of electricity, provide incentives promoting energy efficiency and innovative technology, allow an inventory of energy reserves in the Outer Continental Shelf and support LNG imports and improved leasing and permitting processes in the development of existing supply fields. The effect of this legislation on our future operations is unknown.

Changes in weather conditions. Weather conditions and other natural phenomena can have a material impact on our earnings. Severe weather conditions, including destructive weather patterns such as hurricanes, can impact our suppliers and the pipelines that deliver gas to our distribution system. Weather conditions directly influence the demand for and the cost of natural gas. The specific impacts on Piedmont of Hurricane Katrina may not be known for some time.

Changes in environmental and safety regulations and the cost of compliance. We are subject to extensive federal, state and local regulations. Compliance with such regulations may result in increased capital or operating costs.

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

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

Earnings from our equity method investments. We invest in companies that have risks that are inherent in their businesses and we assume such risks as an equity investor.

All of these factors are difficult to predict and many are beyond our control. Accordingly, while we believe the assumptions underlying our forward-looking statements to be reasonable, there can be no assurance that these statements will approximate actual experience or that the expectations derived from them will be realized. When used in our documents or oral presentations, the words anticipate, believe, seek, intend, plan, estimate, expect, projection, budget, forecast, goal or similar words or future or conditional verbs such as will, would, should may are intended to identify forward-looking statements.

Factors relating to regulation and management are also described or incorporated by reference in our Annual Report on Form 10-K, as amended by our Form 10-K/A for the year ended October 31, 2004, as well as information included in, or incorporated by reference from, future filings with the SEC. Some of the factors that may cause actual results to differ have been described above. Others may be described elsewhere in this report. There may also be other factors besides those described above or incorporated by reference in this report or in the Form 10-K and Form 10-K/A that could cause actual conditions, events or results to differ from those in the forward-looking statements.
Forward-looking statements reflect our current expectations only as of the date they are made. We assume no duty to update these statements should expectations change or actual results differ from current expectations except as required by applicable laws and regulations. Please reference our web site at www.piedmontng.com for current information. Our filings on Form 10-K, Form 10-K/A, Form 10-Q and Form 8-K are available on our web site as soon as reasonably practicable after the report is filed with the SEC.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We hold all financial instruments discussed below for purposes other than trading. We are potentially exposed to market risk due to changes in interest rates and the cost of gas. Our exposure to interest rate changes relates primarily to short-term debt. We are exposed to interest rate changes to long-term debt when we are in the market to issue long-term debt. As of July 31, 2005, all of our long-term debt was at fixed rates. Exposure to gas cost variations relates to the wholesale supply, demand and price of natural gas.

Interest Rate Risk

We have short-term borrowing arrangements to provide working capital and general corporate funds. The level of borrowings under such arrangements varies from period to period depending upon many factors, including investments in capital projects. Future short-term interest expense and payments will be impacted by both short-term interest rates and borrowing levels.
As of July 31, 2005, we had $84 million of short-term debt outstanding. The following table reflects our short-term borrowings during the three months and nine months ended July 31, 2005.

	Three Months		Nine Months	
In thousands	High	Low	High	Low
Outstanding short-term borrowings	$ 112,000	$	$ 229,500	$
Interest rates	3.62%	3.36%	3.62%	2.11%

	Three Months	Nine Months
Weighted average interest rate during the period	3.57%	2.72%

Information about our long-term debt that, for holders of our long-term debt, is sensitive to changes in interest rates is presented below.

In thousands	Expected Maturity Date 2005	2006	2007	2008	2009	Thereafter	Total	Fair Value as of July 31, 2005
Fixed Rate Long Term Debt	$	$ 35,000	$	$	$ 30,000	$ 595,000	$ 660,000	$ 772,206
Average Interest Rate		9.44%			7.35%	6.87%	7.03%	

Commodity Price Risk

In the normal course of business, we utilize exchange-traded contracts of various duration for the forward sale and purchase of a portion of our natural gas requirements. We manage our gas supply costs through a portfolio of short- and long-term procurement contracts with various suppliers and financial price-hedging instruments. Due to cost-based rate regulation in our utility operations, we have limited financial exposure to changes in commodity prices as substantially all changes in purchased gas costs and the costs of hedging our gas supplies are passed on to customers through PGA mechanisms.

Additional information concerning market risk is set forth in Financial Condition and Liquidity in Item 2 of this Form 10-Q.

Item 4. Controls and Procedures

As of July 31, 2005, management, including the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures. Such disclosure controls and procedures are designed to ensure that all information required to be disclosed in our reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Based on our evaluation process, the Chief Executive Officer and the Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report. During the last fiscal quarter, there have been no changes in our internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

We have only routine litigation in the normal course of business and do not expect the outcomes to have any material impact on our financial position or results of operations.

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

a) None.
b) None.

c) Issuer Purchases of Equity Securities.

The following table provides information with respect to repurchases of our Common Stock under the Common Stock Open Market Purchase Program during the quarter ended July 31, 2005.

Period	Total Number of Shares Repurchased	Average Price Paid Per Share	Total Number of Shares Purchased As Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program *
Beginning of the Period				2,237,200
May	111,930	$23.54	111,930	2,125,270
June	137,302	$24.15	137,302	1,987,968
July	91,868	$24.38	91,868	1,896,100
Total	341,100	$24.01	341,100	

* Common Stock Open Market Purchase Program was announced on June 4, 2004, to repurchase up to three million shares of Common Stock. There is no expiration date for the program.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

(a) None.

(b) There have been no changes to the procedures by which security holders may recommend nominees to our Board of Directors.

Item 6. Exhibits

Exhibits

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

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

SIGNATURES

Pursuant to the requirements of 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)

Date: September 8, 2005

/s/ David J. Dzuricky

David J. Dzuricky
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: September 8, 2005

/s/ Barry L. Guy

Barry L. Guy
Vice President and Controller
(Principal Accounting Officer)