RGC RESOURCES INC
Form ARS
December 19, 2008
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YEAR ENDED SEPTEMBER 30,	2008	2007
Operating Revenue - Natural Gas	$ 93,606,593	$ 89,175,661
Other Revenue	$ 1,030,233	$ 725,640
Net Income - Continuing Operations	$ 4,257,824	$ 3,765,669
Net Income (Loss) - Discontinued Operations	$ (36,690)	$ 40,540
Basic Earnings Per Share - Continuing Operations	$ 1.94	$ 1.74
Basic Earnings Per Share - Discontinued Operations	(0.02)	$ 0.02
Regular Dividend Per Share - Cash	$ 1.25	$ 1.22
Number of Customers - Natural Gas	55,689	55,420
Total Natural Gas Deliveries - DTH	9,251,254	9,538,229
Total Additions to Plant	$ 6,539,369	$ 6,004,190

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I am delighted to report EARNINGS OF $4.2 MILLION, **which reflects a 9 percent increase in earnings in a very difficult year for the U.S. economy and financial markets.**

I am delighted to report company earnings of $4.2 million, or $1.91 per average diluted share outstanding. This compares to per share earnings of $1.75 in 2007 and reflects a 9 percent increase in earnings in a very difficult year for the U.S. economy and the financial markets. I am also pleased to report that your Board of Directors elected to raise the annualized dividend rate to $1.28 per share effective with the February 1, 2009, quarterly dividend for shareholders of record on January 17, 2009. This is the Company s 12th dividend increase since 1995 and continues our 64-year record of consecutive quarterly dividend payments to shareholders.

Fiscal 2008 was another busy year for the Company. We sold our Bluefield Gas Company operations, settled a pending Roanoke Gas Company rate case increase in March for $416,000, filed another increase request in September for $1.2 million, carried out a record level of pipeline replacements, and operated through the second most volatile year of natural gas commodity prices in history. Fiscal 2008 was also one of the most volatile stock market and credit-constrained years in recent history.

As I indicated to shareholders last year, I believe the sale of the Bluefield Gas Company operations was an appropriate strategic move for the Company. The sale allowed us to redeploy capital to the Roanoke Gas Company utility system, which has far greater customer growth potential and a much better financial performance record. Our earnings growth in 2008, combined with our enhanced pipeline replacement program, supports the appropriateness of that strategic decision.

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In 2008, our service area experienced a significant slowdown in new home construction, and we consequently had slower customer growth related to the overall economic slowdown and depressed housing market. However, we used the slowdown in new construction as an opportunity to enhance our distribution system renewal program. We installed over 9 miles of new plastic mains associated with our bare steel and cast iron replacement program. We also replaced 684 bare steel main-to-meter service lines with new plastic service lines. Our miles of pipeline installed associated with system renewal increased by over 40 percent and our volume of bare steel service line replacements nearly doubled compared to 2007. A significant portion of the September 2008 rate increase application to the Virginia State Corporation Commission is related to the incremental depreciation expense and carrying cost associated with the higher level of distribution system investment.

The sale of the Bluefield Gas Company operations allowed us

to redeploy capital to the Roanoke Gas Company utility system

which has FAR GREATER CUSTOMER GROWTH POTENTIAL

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Fiscal 2008 was an extremely volatile period for energy commodities. Crude oil prices reached all-time price highs, climbing to over $140 a barrel while natural gas spiked to over $14 a decatherm. Prices then plunged to roughly $60 a barrel for oil and to under $7 a decatherm for natural gas. A rapidly devaluing U.S. dollar, combined with political upheaval in oil producing regions and strong oil demand, led to a real or perceived oil shortage and price extremes. Natural gas prices followed, in spite of increasing domestic production with adequate storage levels. However, in a matter of weeks, oil commodity prices collapsed, as did the perception of demand with the growing worldwide recession. Natural gas prices also dropped dramatically as the market responded to declining demand, increasing domestic production and strong storage levels leading into the winter months.

Prices have now fallen so fast that we may have set ourselves up for another boom/bust cycle, which could lead to a decline in exploration and production, followed by another supply squeeze and price spike when the economy recovers and energy demand again grows. I believe the long-term outlook for energy prices

RGC installed OVER 9 MILES

OF NEW PLASTIC MAINS

associated with our bare steel

and cast iron replacement program.

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Our miles of pipeline installed associated with system renewal

INCREASED BY OVER 40 PERCENT **and our volume of bare steel**

service line replacements nearly DOUBLED COMPARED TO 2007.

will be volatile, but steadily trending higher, particularly given continued world population and long-term energy demand growth. Pressure on natural gas demand and prices will also increase when climate change legislation is enacted by the U.S. Congress and signed into law by the new president. Burning natural gas produces roughly half of the carbon dioxide emissions of coal, so it will become an increasingly favored fuel for electricity generation as electric utilities try to lower their carbon dioxide emissions to comply with new legislative mandates.

The Company so far has weathered the financial crisis and economic decline without disruption. Our working capital credit lines and banking relationships have remained in place and strong. We successfully replaced $5 million of retired long-term debt at a competitive interest rate just after the fiscal year ended. I am also pleased with how well our stock price has held up, even if it has been somewhat more volatile during the extreme stock market swings. The economic slowdown may, however, have more impact on us in 2009 if our larger industrial customers are forced to cut back

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operations in response to reduced demand for their products. We experienced some industrial demand decline early in the first quarter of 2009.

We are pleased to provide you with our 2008 annual report reflecting strong earnings performance. Our annual report this year explores how we are meeting our customers needs by focusing on basics, and is reflective of our long-term commitment to strengthening our energy distribution infrastructure. We look forward to many more years of providing safe and reliable natural gas service to our customers and consistently competitive returns to our shareholders. On behalf of the Board of Directors and employees of RGC Resources, Inc., I thank you for your continuing interest in our operations and for your decision to be a shareholder.

Sincerely,

John B. Williamson, III

Chairman, President and CEO

RGC has WEATHERED

THE FINANCIAL CRISIS

AND ECONOMIC DECLINE

WITHOUT DISRUPTION.

Our working capital credit lines and

banking relationships have remained

IN PLACE AND STRONG.

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Officers and Board of Directors

OFFICERS

John B. Williamson, III

Chairman of the Board, President and Chief Executive Officer (1)(2)(3)(4)

John S. D Orazio

Vice President and Chief Operating Officer (2)(3)(4)

Howard T. Lyon

Vice President, Treasurer and Chief Financial Officer (1)(2)(3)(4)

Dale P. Lee

Vice President and Secretary (1)(2)(3)(4)

Jane N. O Keeffe

Vice President, Human Resources (1)

Robert L. Wells

Vice President, Information Technology, Assistant Secretary and Assistant Treasurer (1)(3)(4)

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Chief Operating Officer/Executive Vice President

Carilion Clinic

Director: (1)(2)

Abney S. Boxley, III

President and Chief Executive Officer

Boxley Materials Company

Director: (1)(2)

Frank T. Ellett

President

Virginia Truck Center, Inc.

Director: [1][2]

Maryellen F. Goodlatte

Attorney and Principal

Glenn Feldmann Darby & Goodlatte

Director: [1][2]

J. Allen Layman

Private Investor

Director: [1][2]

George W. Logan

Chairman of the Board

Valley Financial Corporation

Principal

Pine Street Partners

Faculty

University of Virginia Darden Graduate School of Business

Director: [1]

S. Frank Smith

Vice President Eastern Sales Market Analysis & Research

Alpha Coal Sales Company, LLC

Director: [1][2]

Raymond D. Smoot, Jr.

Chief Operating Officer and Secretary-Treasurer

Virginia Tech Foundation, Inc.

Director: [1]

John B. Williamson, III

Chairman of the Board, President and Chief Executive Officer

Director: [1][2][3][4]

SUBSIDIARY BOARDS OF DIRECTORS:

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Vice President and Chief Operating Officer

Roanoke Gas Company

Director: [3][4]

Howard T. Lyon

Vice President, Treasurer and Controller

RGC Resources, Inc.

Director: [3][4]

Dale P. Lee

Vice President and Secretary

RGC Resources, Inc.

Director: [3][4]

Robert L. Wells

Vice President, Information Technology, Assistant Secretary and Assistant Treasurer

RGC Resources, Inc.

Director: [3][4]

(1) *RGC Resources, Inc.*
(2) *Roanoke Gas Company*
(3) *Diversified Energy Company*
(4) *RGC Ventures of Virginia, Inc.*

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Selected Financial Data

Years Ended September 30,	**2008**	**2007**	**2006**	**2005**	**2004**
Operating Revenues	$ 94,636,826	$ 89,901,301	$ 94,590,872	$ 88,600,836	$ 74,152,594
Gross Margin	25,913,612	25,221,776	23,208,272	22,206,395	20,655,455
Operating Income	8,838,026	7,958,279	6,677,500	6,395,564	4,270,554
Net Income - Continuing Operations	4,257,824	3,765,669	2,961,802	2,916,798	1,627,165
Net Income (Loss) - Discontinued Operations	(36,690)	40,540	549,729	590,108	11,306,848
Basic Earnings Per Share- Continuing Operations	$ 1.94	$ 1.74	$ 1.40	$ 1.40	$ 0.80
Basic Earnings Per Share- Discontinued Operations	(0.02)	0.02	0.26	0.29	5.58*
Cash Dividends Declared Per Share	$ 1.25	$ 1.22	$ 1.20	$ 1.18	$ 5.67
Book Value Per Share	19.79	19.38	18.94	18.18	17.73
Average Shares Outstanding	2,201,263	2,162,803	2,120,267	2,079,851	2,027,908
Total Assets	118,127,714	116,332,455	114,662,572	113,563,416	114,972,556
Long-Term Debt (Less Current Portion)	23,000,000	23,000,000	28,000,000	28,000,000	24,000,000
Stockholders Equity	43,723,058	42,365,233	40,494,868	38,157,357	36,621,522
Shares Outstanding at Sept. 30	2,209,471	2,186,143	2,138,595	2,098,935	2,065,408

* Reflects $4.69 gain on sale of assets.

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that relate to future transactions, events or expectations. In addition, RGC Resources, Inc. (Resources or the Company) may publish forward-looking statements relating to such matters as anticipated financial performance, business prospects, technological developments, new products, research and development activities and similar matters. These statements are based on management s current expectations and information available at the time of such statements and are believed to be reasonable and are made in good faith. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements. In order to comply with the terms of the safe harbor, the Company notes that a variety of factors could cause the Company s actual results and experience to differ materially from the anticipated results or other expectations expressed in the Company s forward-looking statements. The risks and uncertainties that may affect the operations, performance, development and results of the Company s business include, but are not limited to, the following: (i) failure to earn on a consistent basis an adequate return on invested capital; (ii) ability to retain and attract professional and technical employees; (iii) the potential loss of large-volume industrial customers to alternate fuels, facility closings or production changes; (iv) volatility in the price and availability of natural gas; (v) uncertainty in the demand for natural gas in the Company s service area; (vi) general economic conditions both locally and nationally; (vii) increases in interest rates; (viii) increased customer delinquencies and conservation efforts resulting from high fuel costs, difficult economic conditions and/or colder weather; (ix) variations in winter heating degree-days from the 30-year average on which the Company s billing rates are set; (x) impact of potential climate change legislation regarding limitations on carbon dioxide emissions; (xi) impact of potential increased regulatory oversight and compliance requirements due to financial, environmental, safety and system integrity laws and regulations; (xii) failure to obtain timely rate relief for increasing operating or gas costs from regulatory authorities; (xiii) capital market conditions and the availability of debt and equity financing; (xiv) impact of terrorism; (xv) volatility in actuarially determined benefit costs and plan asset performance; (xvi) effect of natural disasters on production and distribution facilities and the related effect on supply availability and price; and (xvii) changes in accounting regulations and practices, which could change the accounting treatment for certain transactions. All of these factors are difficult to predict and many are beyond the Company s control. Accordingly, while the Company believes its forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. When used in the Company s documents or news releases, the words, anticipate, believe, intend, plan, estimate, expect, objective, projection, forecast, budget, assume, indicate or similar words or future or conditional verbs such as will, would, shoul may are intended to identify forward-looking statements.

Forward-looking statements reflect the Company s current expectations only as of the date they are made. The Company assumes no duty to update these statements should expectations change or actual results differ from current expectations except as required by applicable laws and regulations.

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Management s Discussion & Analysis

OVERVIEW

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 56,000 residential, commercial and industrial customers in Roanoke, Virginia and the surrounding areas through its Roanoke Gas Company (Roanoke Gas) subsidiary. The utility operations of Roanoke Gas are regulated by the Virginia State Corporation Commission (SCC or Virginia Commission). Natural gas service is provided at rates and for the terms and conditions set forth by the SCC. Roanoke Gas currently holds the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia service areas. These franchises are effective through January 1, 2016. While there are no assurances, the Company believes that it will be able to negotiate acceptable franchises when the current agreements expire. Certificates of public convenience and necessity in Virginia are exclusive and are intended to be of perpetual duration.

Resources also provided regulated sale and distribution of natural gas to Bluefield, West Virginia, the Town of Bluefield, Virginia and surrounding areas through its Bluefield Gas Company (Bluefield Gas) subsidiary and the Bluefield division of Roanoke Gas (collectively called Bluefield Operations). Effective as of October 31, 2007, Resources closed on the sale of the stock of Bluefield to ANGD, LLC and Roanoke Gas completed the sale of the assets of its Bluefield division to Appalachian Natural Gas Company, a subsidiary of ANGD, LLC. The Bluefield Operations represented approximately 8% of the natural gas customers of Resources. The corresponding activities of the Bluefield Operations have been classified in discontinued operations as discussed in more detail in the Discontinued Operations section below and footnote 2 of the consolidated financial statements.

Resources also provides certain unregulated natural gas related services through Roanoke Gas Company and information system services through RGC Ventures, Inc. of Virginia, which operates as Application Resources. The unregulated operations represent less than 3% of revenues and margins of Resources.

With the exception of the Discontinued Operations section below, all discussion and analysis excludes the activities of the Bluefield Gas Operations.

Winter weather conditions and volatility in natural gas prices both have a direct influence on the quantity of natural gas sales, and management believes each factor has the potential to significantly impact earnings. A majority of natural gas sales are for space heating during the winter season. Consequently, during warmer than normal (normal refers to the average heating degree-days for a specified period) winters or unevenly cold winters, customers may significantly reduce their consumption of natural gas. Furthermore, significant increases in natural gas commodity prices could also affect customer usage by encouraging conservation or the use of alternative fuels.

Because the SCC authorizes billing rates for the utility operations of Roanoke Gas based on normal winter weather, warmer than normal weather may result in the Company failing to earn its authorized rate of return. The Company has been able to mitigate a portion of the risk associated with warmer than normal winter weather by the inclusion of a weather normalization adjustment (WNA) factor as part of its rate structure, which allows the Company to recover revenues equivalent to the margin that would have been realized at approximately 6% warmer than the 30-year normal. The WNA factor operates based on a weather occurrence band around the most recent 30-year temperature average for the Company s service area, whereby if the number of heating degree-days (an industry measure by which the average daily temperature falls below 65 degrees Fahrenheit) fall within approximately 6% above or below the 30-year average, no adjustment would be made. However, if the number of heating degree-days were more than 6% below the 30-year average, the Company would add a surcharge to firm customer bills (those customers not subject to service interruption) equal to the equivalent margin lost below the approximate 6% level. Likewise, if the number of heating degree-days were more than 6% above the 30-year average, the Company would credit firm customer bills equal to the excess margin realized above the 6% heating degree-day level. The measurement period in determining the weather band extends from April through March with any adjustment to be made to customer bills in late spring. The Company recorded approximately $363,000 in additional revenues in fiscal 2008 to reflect the impact of the WNA for the difference in margin realized for weather that was 11% warmer than the 30-year average over the 6% level during the WNA period ended March 31, 2008. In fiscal 2007, the Company recorded approximately $439,000 in additional revenues for the WNA period ended March 31, 2007 for the difference in margin realized for weather that was 12% warmer than the 30-year average over the 6% level.

Management also has concerns regarding the volatility of natural gas prices and the potential for reduced sales in response to increasing prices. Rising natural gas prices, due to increasing demand and limitations to accessible supply, may influence the level of sales due to conservation efforts by customers or by their switching to an alternative fuel, particularly in the industrial market. In addition, increasing prices may increase the level of bad debts due to customers inability to afford the higher prices. During the late spring and early summer of fiscal 2008, natural gas commodity prices nearly doubled the winter price to almost $14 a decatherm before returning to the $7 range at September 30. Although, the prices did not have a significant effect on gas sales due to the normally lower summer sales volumes, these higher prices caused higher-priced gas to be injected into storage. The unit price of gas in storage has increased by 31% over September 30, 2007 s balance. This increase in storage cost will result in higher billing rates to customers during the coming heating season. Supply disruptions, extended periods of cold weather or volatility in the commodities market could also serve to increase the winter gas supply costs.

With regard to the effect of higher natural gas prices on storage gas, the Company has an approved rate structure in place that mitigates the impact of financing costs of inventory related to rising natural gas prices. Under this rate structure, Roanoke Gas accrues revenue to cover the financing costs or carrying costs related to the level of investment in natural gas inventory. During times of rising gas costs and rising inventory levels, the company recognizes revenues to offset higher financing costs associated with higher inventory balances. Conversely, during times of decreasing inventory costs and lower inventory balances, the Company would recognize less carrying cost revenue as the financing costs would be less. The Company recognized approximately $2,351,000 and $1,955,000 in carrying cost revenues for the years ended September 30, 2008 and 2007.

For the fiscal year ended September 30, 2008, the implementation of a non-gas rate increase, higher inventory carrying cost revenues and reductions in operating expenses more than offset the effect of reduced natural gas sales volumes and increases in maintenance, depreciation and interest expense.

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RESULTS OF OPERATIONS   CONTINUING OPERATIONS

Fiscal Year 2008 Compared with Fiscal Year 2007

Delivered Volumes   The table below reflects volume activity and heating degree-days.

Year Ended September 30,	2008	2007	Increase/ (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Tariff Sales	6,471,825	6,802,773	(330,948)	-5%
Transportation	2,779,429	2,735,456	43,973	2%
Total	9,251,254	9,538,229	(286,975)	-3%
Heating Degree Days (Unofficial)	3,624	3,735	(111)	-3%

Operating Revenues - The table below reflects operating revenues.

Year Ended September 30,	2008	2007	Increase/ (Decrease)	Percentage
Gas Utilities	$ 93,606,593	$ 89,175,661	$ 4,430,932	5%
Other	1,030,233	725,640	304,593	42%
Total Operating Revenues	$ 94,636,826	$ 89,901,301	$ 4,735,525	5%

Total gas utility operating revenues for the year ended September 30, 2008 (fiscal 2008) increased by 5% over fiscal 2007 even though total delivered volumes declined by 3%. The increase in gas revenues resulted from a steady increase in the commodity price of gas from March through July, with the price climbing from $8.00 to nearly $14.00 a decatherm at its peak. The most significant increases in price occurred during the late spring and early summer when sales volumes are lower; consequently, the effect on revenues was not as significant as it would have been had prices spiked during the heating season. Since July, the commodity price of natural gas has declined to the $7.00 range. For the year, the average per unit cost of natural gas reflected in cost of sales increased by 12%. From a volume perspective, tariff sales, consisting primarily of the more weather sensitive residential and commercial customers, declined by 5% primarily due to a 3% reduction in the number of heating degree-days. Transportation sales increased by 2%, holding steady with last years delivered volumes.

Other revenues increased by 42% primarily due to paving services provided to another local utility under an agreement through the end of December 2008.

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Gross Margin - The table below reflects gross margins.

Year Ended September 30,	2008	2007	Increase/ (Decrease)	Percentage
Gas Utilities	$ 25,323,464	$ 24,833,279	$ 490,185	2%
Other	590,148	388,497	201,651	52%
Total Gross Margin	$ 25,913,612	$ 25,221,776	$ 691,836	3%

Gas utility margins increased by 2% due to the combination of a non-gas rate increase and higher inventory carrying cost revenues even though total delivered volume (tariff and transportation) declined by 3% from last year. In November 2007, Roanoke Gas placed increased non-gas rates into effect subject to refund pending a final order from the Virginia Commission. In April 2008, Roanoke Gas received a final rate order approving approximately $416,000 in additional annual revenues based on normal winter weather. The rate increase provided for both a higher customer base charge, the flat monthly fee billed to each natural gas customer, and a higher volumetric rate. As a result of the rate increase and customer growth, customer base charges accounted for approximately $385,000 of the increase in margin and the increased level of gas in storage provided approximately $395,000 in additional inventory carrying cost revenues. Volumetric sales margins declined by approximately $265,000 as lower delivered volumes more than offset increases in the volumetric billing rates.

Other margins increased by $201,651 primarily due to paving services.

Other Operating Expenses Operations expenses decreased $517,313, or 5%, in fiscal 2008 compared with fiscal 2007 as reductions in employee benefit costs, professional and contractor services and greater level of capitalized overheads more than offset increases in operations labor and bad debt expense. Employee benefit expenses decreased due to a $123,000 reduction in pension costs attributable to higher expected returns on higher plan asset levels and no amortization of an actuarial loss in fiscal 2008 combined with a $47,000 reduction in health insurance premiums. The Company expects both pension costs and medical costs to increase significantly in fiscal 2009. Professional services decreased $181,000 due to less reliance on external assistance related to internal control documentation and testing, lower actuarial expenses, the absence of fees for consent reviews from prior external auditors and reduced levels of computer systems consulting. Increased level of capital activity and production of LNG (liquefied natural gas) reduced operating expenses due to the capitalization of an additional $261,000 of overheads. Bad debt expense increased $76,000 due to the effect of higher natural gas prices and lower recoveries of prior bad debt write-offs. The remaining difference resulted from a variety of other minor expense variances.

Maintenance expenses increased by $50,382, or 4% as a result of higher LNG repairs and computer software and systems maintenance.

General taxes increased $36,77, or 3% in fiscal 2008 compared to fiscal 2007 due to property taxes on a greater level of taxable property.

Depreciation expense increased by $242,249, or 6% due to higher natural gas plant investment from adding new natural gas customers and pipeline renewal projects.

Other Income (Expense) Other income (expense) switched from a net expense position in fiscal 2007 to a net income position in 2008 due to the earnings on the $1,300,000 note from ANGD, LLC received as part of the proceeds on the sale of the Bluefield, Virginia portion of assets.

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Interest Expense Total interest expense for fiscal 2008 increased by $101,638, or 5%, from fiscal 2007, as a result of an increase in average debt outstanding attributable to an increased investment in natural gas storage inventories, utility plant, accounts receivable and under-recovery of gas costs more than offsetting the decline in the average effective interest rate on the Company s line of credit.

Income Taxes Income tax expense from continuing operations increased $345,334, or 15%, from fiscal 2007 corresponding to a 14% increase in pre-tax earnings. The effective tax rate for fiscal 2008 was 37.7% compared to 37.3% in fiscal 2007.

Net Income and Dividends Income from continuing operations for fiscal 2008 was $4,257,824 compared to $3,765,669 for fiscal 2007. Basic and diluted earnings per share from continuing operations were $1.94 and $1.93 in fiscal 2008 compared with $1.74 and $1.73 in fiscal 2007. Dividends declared per share of common stock were $1.25 in fiscal 2008 and $1.22 in fiscal 2007.

DISCONTINUED OPERATIONS

As discussed in footnote 2 of the consolidated financial statements, effective as of October 31, 2007, Resources closed on the sale of the stock of Bluefield Gas to ANGD, LLC, and Roanoke Gas completed the sale of its natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia (Bluefield division of Roanoke Gas) to Appalachian Natural Gas Company, a subsidiary of ANGD, LLC.

The Bluefield Operations previously absorbed approximately $750,000 annually in costs allocated from Resources and Roanoke Gas that continued after the sale. The Company recovered a portion of these costs through a services agreement with ANGD and through non-gas cost rate filings. The Company also reduced a portion of these costs through staff reductions.

Although the Purchase and Sale Agreement with ANGD for the sale of the capital stock of Bluefield Gas provided for a sales price substantially equal to the book value of Bluefield s net assets on the date of closing, the underlying tax basis that Resources had in the stock was significantly less than its book basis. This lower tax basis resulted in the recording of an income tax expense of approximately $535,000 attributable to the taxable gain for the excess of the book basis of the assets over the tax basis. The tax liability was reflected as part of income tax expense in discontinued operations for fiscal 2007.

ASSET MANAGEMENT

Roanoke Gas uses a third party as an asset manager to manage its pipeline transportation, storage rights and gas supply inventories and deliveries. In return for being able to utilize the excess capacities of the transportation and storage rights, the third party pays Roanoke Gas a monthly utilization fee, which is used to reduce the cost of gas for customers. The current agreement expires in October 2010.

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CAPITAL RESOURCES AND LIQUIDITY

Due to the capital intensive nature of the utility business, as well as the related weather sensitivity, the Company s primary capital needs are the funding of its continuing construction program, the seasonal funding of its natural gas inventories and accounts receivable and payment of dividends. To meet these needs, the Company relies on its operating cash flows, line-of-credit agreements, long-term debt and capital raised through the Company s Dividend Reinvestment and Stock Purchase Plan (DRIP).

Cash and cash equivalents decreased by $532,881 in fiscal 2008 compared to $81,824 decrease in fiscal 2007. The following table summarizes the categories of sources and uses of cash:

Year Ended September 30,	**2008**	**2007**
Continuing operations:		
Provided by operating activities	$ 497,778	$ 5,630,055
Used in investing activities	(3,166,506)	(5,991,850)
Provided by financing activities	2,061,120	15,761
Cash provided by discontinued operations	74,727	264,210
Decrease in cash and cash equivalents	$ (532,881)	$ (81,824)

Due to the seasonal nature of the natural gas business, operating cash flows may fluctuate significantly during the year as well as from year to year. Factors including weather, energy prices, natural gas storage levels and customer collections all contribute to working capital levels and the related cash flows. Generally, operating cash flows are positive during the second and third quarters as a combination of earnings, storage gas levels and collections on customer accounts all contribute to higher cash levels. During the first and fourth quarters, operating cash flows generally decrease due to the increases in natural gas storage levels, rising customer receivable balances and construction activity. In fiscal 2008, cash provided by continuing operating activities decreased by approximately $5,100,000, from $5,600,000 in fiscal 2007 to $500,000 in fiscal 2008, as purchases for gas in storage increased due to the sharp rise in the commodity price of natural gas during the late spring and early summer. The higher prices resulted in an increase in gas in storage balances of approximately $7,000,000 over the same period last year. Increases in net income and accounts payable balances associated with the higher gas costs partially offset the decrease in operating cash flows.

Investing activities are generally composed of expenditures under the Company s construction program, which involves a combination of replacing aging bare steel and cast iron pipe with new plastic or coated steel pipe and expansion of its natural gas system to meet the demands of customer growth. Cash flows used in investing activities declined by approximately $2,800,000 due to cash proceeds received from the sale of Bluefield Operations. Total capital expenditures from continuing operations were approximately $6,500,000 and $6,000,000 for the years ended September 30, 2008 and 2007, respectively. Although new construction related to expanding natural gas service has declined due to the current slow down in real estate development and economic environment, the Company plans to continue its focus on pipeline renewals and expects such expenditures to continue for the next several years. Operating cash flow provided by depreciation contributed approximately $4,500,000 in support of fiscal 2008 capital expenditures, or approximately 69% of the total investment, compared to approximately $4,300,000, or 72% of the total investment in fiscal 2007. The Company also relies on its line-of-credit agreements, other operating cash flows and long-term debt financing to provide the underlying funding its capital expenditures.

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Resources and Roanoke Gas closed on the sale of the Bluefield Operations effective as of October 31, 2007. The Company received approximately $3,800,000 after retirement of Bluefield s outstanding debt and a subordinated note of $1,300,000. The Company used the net proceeds to infuse capital into Roanoke Gas to help fund its construction and pipeline renewal programs. Resources also invested $500,000 of the proceeds from the sale of Bluefield Gas stock in a short-term investment.

Financing activities generally consist of long-term and short-term borrowings and repayments, issuance of stock and the payment of dividends. Cash flow from continuing financing activities increased by approximately $2,000,000 over fiscal 2007 due to increased borrowing under the Company s line-of-credit agreement. As discussed above, the Company uses its line-of-credit arrangements to fund seasonal working capital needs as well as provide temporary financing for capital projects. Total cash provided by the line-of-credit for Roanoke Gas increased by $9,150,000. $5,000,000 of the increase was used to retire Roanoke Gas first mortgage note that matured on July 1, 2008. The remainder of the increase was used to support the higher investment in storage gas inventories and capital expenditure financing.

On June 30, 2008, the Company executed a new line-of-credit agreement for Roanoke Gas. The new agreement increases the total available line-of-credit for the balance of the term of the original note dated March 28, 2008. Significantly higher natural gas prices at the time prompted the need for additional working capital to fund natural gas purchases and accounts receivable. The Company is currently evaluating its funding needs under the line-of-credit agreement for Roanoke Gas and may reduce the available balances in light of the lower commodity price of gas. The line-of-credit agreements expire March 31, 2009, unless extended. The Company anticipates being able to extend or replace the line-of-credit agreements upon expiration. The Company s total available limits under the remaining term of the line-of-credit agreements are as follows:

Beginning	Available Limit
September 30, 2008	$ 27,000,000
November 16, 2008	29,000,000
February 16, 2009	16,000,000

The remainder of the financing cash flows was associated with approximately $641,000 of proceeds related to stock issuances under the DRIP and approximately $2,700,000 in dividends paid.

On October 31, 2008, the Roanoke Gas executed a $5,000,000 variable-rate promissory note due December 1, 2015 to replace the first mortgage note that matured on July 1, 2008. The interest rate on the note is LIBOR plus 125 basis points. Roanoke Gas also entered into an interest-rate swap agreement for the same term as the note to effectively convert the variable-rate note into a fixed-rate debt with an interest rate of 5.79%.

At September 30, 2008, the Company s consolidated long-term capitalization was 65% equity and 35% debt, compared to 60% equity and 40% debt at September 30, 2007. If the $5,000,000 variable-rate note had been in place at September 30, 2008, the Company s long-term capitalization would have been 61% equity and 39% debt.

REGULATORY AFFAIRS

On November 1, 2007, Roanoke Gas Company placed into effect new base rates to provide for approximately $700,000 in additional annual revenues, subject to refund. The Company received the final order from the SCC on May 22, 2008 approving rates, which provided for approximately $416,000 in additional annual revenues. In June 2008, the Company completed its refund of rates billed in excess of the amount authorized by the final order, including interest on the excess amount.

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On September 16, 2008, the Company filed a request for an expedited rate increase with the SCC. The request was for an increase of approximately $1,198,000 in annual non-gas revenues. Under an expedited rate request, the Company is able to place the increased rates into effect for service rendered on and after November 1, 2008, subject to refund pending a final order by the SCC. The hearing on the request for rate increase is scheduled for late March 2009, with a final order expected some time after that date.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The consolidated financial statements of Resources are prepared in accordance with accounting principles generally accepted in the United States of America. The amounts of assets, liabilities, revenues and expenses reported in the Company s financial statements are affected by accounting policies, estimates and assumptions that are necessary to comply with generally accepted accounting principles. Estimates used in the financial statements are derived from prior experience, statistical analysis and professional judgments. Actual results may differ significantly from these estimates and assumptions.

The Company considers an 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 are reasonably likely to occur from period to period. The Company considers the following accounting policies and estimates to be critical.

Regulatory accounting The Company s regulated operations follow the accounting and reporting requirements of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71). The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities).

If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the Company would remove the regulatory assets or liabilities from the balance sheet related to those portions no longer meeting the criteria and include them in the consolidated statement of income and comprehensive income for the period in which the discontinuance occurred.

Revenue recognition Regulated utility sales and transportation revenues are based upon rates approved by the SCC. The non-gas cost component of rates may not be changed without a formal rate increase application and corresponding authorization by the SCC; however, the gas cost component of rates may be adjusted periodically through the PGA mechanism with approval from the SCC.

The Company bills its regulated natural gas customers on a monthly cycle. The billing cycle periods for most customers do not coincide with the accounting periods used for financial reporting. The Company accrues estimated revenue for natural gas delivered to customers not yet billed during the accounting period. Determination of unbilled revenue relies on the use of estimates, weather during the period and current and historical data. The financial statements included unbilled revenue of $1,475,406 and $1,287,362 as of September 30, 2008 and 2007.

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Allowance for Doubtful Accounts The Company evaluates the collectibility of its accounts receivable balances based upon a variety of factors including loss history, level of delinquent account balances and general economic climate.

Pension and Postretirement Benefits The Company offers a defined benefit pension plan (pension plan) and a postretirement medical and life insurance plan (postretirement plan) to eligible employees. The expenses and liabilities associated with these plans, as disclosed in footnote 7 to the consolidated financial statements, are based on numerous assumptions and factors, including provisions of the plans, employee demographics, contributions made to the plan, return on plan assets and various actuarial calculations, assumptions and accounting requirements. In regard to the pension plan, specific factors include assumptions regarding the discount rate used in determining future benefit obligations, expected long-term rate of return on plan assets, compensation increases and life expectancies. Similarly, the postretirement medical plan also requires the estimation of many of the same factors as the pension plan in addition to assumptions regarding the rate of medical inflation and Medicare availability. Actual results may differ materially from the results expected from the actuarial assumptions due to changing economic conditions, volatility in interest rates and changes in life expectancy. Such differences may result in a material impact on the amount of expense recorded in future periods or the value of the obligations on the balance sheet.

In selecting the discount rate to be used in determining the benefit liability, the Company considered the rates of return on high-quality fixed-income investments that corresponded to the benefit streams expected under both the pension plan and postretirement plan. The Company also used an asset/liability model to evaluate the probability of meeting the returns on its targeted investment allocation model. The investment policy as of the measurement date in June reflected a targeted allocation of 60% equity and 40% fixed income for an assumed long-term rate of return of 7.5% on the pension plan and a targeted allocation of 50% equity and 50% fixed income for an assumed long-term rate of return of 5.22% (net of income taxes) for the postretirement plan. Based on the assumptions described above and in footnote 7, pension expense is expected to increase from approximately $378,000 in fiscal 2008 to $459,000 in fiscal 2009 and postretirement expense is expected to go from approximately $554,000 in fiscal 2008 to $540,000 in fiscal 2009. The Company expects to contribute approximately $600,000 each to its pension and postretirement plans. However, funding requirements under the Pension Protection Act of 2006 could require the Company to increase its projected contribution levels if the plans funded status is significantly deteriorated by the current economic environment.

The following schedule reflects the sensitivity of pension costs to changes in certain actuarial assumptions, assuming that the other components of the calculation remain constant.

Actuarial Assumption	Change in Assumption	Impact on 2008 Pension Cost	Impact on Projected Benefit Obligation
Discount rate	-0.25%	$ 66,000	$ 568,000
Rate of return on plan assets	-0.25%	29,000	N/A
Rate of increase in compensation	0.25%	42,000	218,000

The following schedule reflects the sensitivity of postretirement benefit costs from changes in certain actuarial assumptions, while the other components of the calculation remain constant.

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Actuarial Assumption	Change in Assumption	Impact on 2008 Postretirement Benefit Cost	Impact on Accumulated Benefit Obligation
Discount rate	-0.25%	$ 11,000	$ 260,000
Rate of return on plan assets	-0.25%	13,000	N/A
Health care cost trend rate	0.25%	28,000	235,000

Since June 30, 2008, the measurement date used for determining several of the actuarial assumptions as well as determining the market value of the plan assets of both the pension plan and postretirement medical plan, the economic crisis resulting from issues in the credit markets have significantly reduced the value of the plan assets. Although the determination of fiscal 2009 expense components has already been determined, the recent decline in asset values, if not reversed, has the potential to significantly affect funded status, future funding requirements and expense recognition in future financial statements.

Derivatives The Company may hedge certain risks incurred in its operation through the use of derivative instruments. The Company applies the requirements of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, which requires the recognition of derivative instruments as assets or liabilities in the Company s balance sheet at fair value. In most instances, fair value is based upon quoted futures prices for natural gas commodities and interest rate futures for interest rate swaps. Changes in the commodity and futures markets will impact the estimates of fair value in the future. Furthermore, the actual market value at the point of realization of the derivative may be significantly different from the values used in determining fair value in prior financial statements.

MARKET RISK

The Company is exposed to market risks through its natural gas operations associated with commodity prices. The Company s risk management policy, as authorized by the Company s Board of Directors, allows management to enter into both physical and financial transactions for the purpose of managing commodity risk of its business operations. The policy also specifies that the combination of all commodity hedging contracts for any 12-month period shall not exceed a total hedged volume of 90% of projected volumes. Finally, the policy specifically prohibits the utilization of derivatives for the purposes of speculation.

The Company manages the price risk associated with purchases of natural gas by using a combination of liquefied natural gas (LNG) storage, storage gas, fixed price contracts, spot market purchases and derivative commodity instruments including futures, price caps, swaps and collars.

As of September 30, 2008, the Company had collar agreements outstanding for the purpose of hedging the price of natural gas during the winter period for 370,000 decatherms. Any cost incurred or benefit received from the derivative or other hedging arrangements would be expected to be recoverable or refunded through the regulated natural gas purchased gas adjustment (PGA) mechanism. The SCC currently allows for full recovery of prudent costs associated with natural gas purchases, and any additional costs or benefits associated with the settlement of the derivative contracts will be passed through to customers when realized.

The Company is also exposed to market risk related to changes in interest rates associated with its borrowing activities. As of September 30, 2008, the Company had $13,960,000 outstanding under its lines-of-credit. Based upon outstanding borrowings at September 30, 2008, a 100 basis point increase in market interest rates applicable to the Company s variable rate debt would have resulted in an increase in annual interest expense of approximately $139,000.

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OTHER RISKS

The Company is exposed to certain risks other than commodity and interest rates. Such other events, situations or conditions have or potentially could have an impact on the future results of operations of the Company. For most of the items described below, the regulated natural gas operations in Virginia have a means to recover increased costs through formal rate application filings, as well as the ability to automatically pass along increases in natural gas cost. However, rate applications are generally filed based upon historical expenses, which generally results in the Company lagging in the recovery of rapidly increasing operating expenses. Moreover, there can be no guarantee that the SCC will allow recovery for all such increased costs when rate applications are filed.

Regulatory and Governmental Actions As discussed above, Virginia has a means to allow the regulated operations of the Company to recover increased costs and earn a reasonable rate of return on equity. The SCC is the state agency responsible for regulating the operations of Roanoke Gas and approves the rates charged to its customers. If the SCC were to impose limitations to delay or prohibit the Company from placing rates into effect to timely recover costs and earn a rate of return, the earnings of the Company could be impacted. Furthermore, legislation at the state or federal level could impose undue costs and burdens on the Company from both a cost and operational perspective.

Energy Prices Energy costs represent the single largest expense of the Company with the cost of natural gas representing approximately 80% and 79% for fiscal 2008 and 2007 of the total operating expenses of the Company s natural gas utility operations. Increases or decreases in natural gas costs are passed through to customers under the present PGA mechanism. As discussed above, increases in the commodity price of natural gas may cause existing customers to conserve or switch to alternate sources of energy. High natural gas prices may also discourage new home developers and new potential customers from selecting natural gas as their energy choice. Furthermore, during periods when natural gas prices are significantly higher than historical levels, customers may have much greater difficulty paying their natural gas bills, resulting in higher bad-debt expense and lower earnings. Roanoke Gas Company s rate structure provides a level of protection against the impact that rising energy prices may have on bad debts by providing for recovery of these costs. However, the rate structure will not protect the Company from increases in the rate of bad debts.

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Credit and Customer Gas costs represent a major portion of the total customer bill. The Company has worked diligently at minimizing bad debts and bad-debt write offs. However, management anticipates that future significant increases or spikes in natural gas prices could result in an increased rate of delinquencies as customers face higher natural gas bills as well as other higher energy costs. In addition, the SCC has specific notice requirements with which the Company must comply before disconnecting natural gas service for customer nonpayment. The Company has mitigated some of the risk through increased deposit requirements based upon higher energy prices, as well as obtaining credit insurance coverage on certain of the Company s larger volume industrial customers. Furthermore, the Company s approved rate structure provides a level of protection against the impact that rising energy prices may have on bad debts. Nevertheless, the Company has no such protection if the percentage of bad debts to revenues increases above recent historical levels.

Weather The nature of the Company s business is highly dependent upon weather specifically, winter weather. Cold weather increases energy consumption by customers and therefore increases revenues and margins. Conversely, warm weather reduces energy consumption and ultimately revenues and margins. Since 2003, Roanoke Gas Company s rate structure has included a weather normalization adjustment factor as discussed above. The Company should be at risk for no more than a 6% swing in heating degree-days above or below average.

Credit and Capital Availability The capital intensive and seasonal nature of the utility operations requires the access to sufficient levels of debt and equity capital. Recent events in the credit and financial markets have impacted the cost and availability of short-term and long-term credit funding. The Company was able to complete the financing of a $5 million unsecured promissory note on October 31; however, continued uncertainty in financial markets could negatively affect the availability and price of the Company s line-of-credit agreements. Although the Company believes that it will be able to renew these agreements, it is uncertain whether the renewal will be under the same or less favorable terms. The failure to obtain funding when needed, or obtain funding only on unfavorable terms, could have a significant negative impact to the Company.

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Capitalization Statistics

Years Ended September 30,	**2008**	**2007**	**2006**	**2005**	**2004**
COMMON STOCK:					
Shares Issued	2,209,471	2,186,143	2,138,595	2,098,935	2,065,408
Continuing Operations:					
Basic Earnings Per Share	$ 1.94	$ 1.74	$ 1.40	$ 1.40	$ 0.80
Diluted Earnings Per Share	$ 1.93	$ 1.73	$ 1.39	$ 1.39	$ 0.80
Discontinued Operations:					
Basic Earnings Per Share	$ (0.02)	$ 0.02	$ 0.26	$ 0.29	$ 5.58*
Diluted Earnings Per Share	$ (0.02)	$ 0.02	$ 0.26	$ 0.29	$ 5.53
Dividends Paid Per Share (Cash)	$ 1.25	$ 1.22	$ 1.20	$ 1.18	$ 5.67
Dividends Paid Out Ratio	65.1%	69.3%	72.3%	69.8%	88.9%
CAPITALIZATION RATIOS:					
Long-Term Debt, Including Current Maturities	34.5	39.8	40.9	42.3	39.6
Common Stock And Surplus	65.5	60.2	59.1	57.7	60.4
Total	100.0	100.0	100.0	100.0	100.0
Long-Term Debt, Including Current Maturities	$ 23,000,000	$ 28,000,000	$ 28,000,000	$ 28,000,000	$ 24,019,987
Common Stock And Surplus	43,723,058	42,365,233	40,494,868	38,157,357	36,621,522
Total Capitalization Plus Current Maturities	$ 66,723,058	$ 70,365,233	68,494,868	66,157,357	60,641,509

* Reflects $4.69 gain on sale of assets.

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Market Price and Dividend Information

RGC Resources common stock is listed on the Nasdaq National Market under the trading symbol RGCO. Payment of dividends is within the discretion of the Board of Directors and will depend on, among other factors, earnings, capital requirements, and the operating and financial condition of the Company. The Company s long-term indebtedness contains restrictions on dividends based on cumulative net earnings and dividends previously paid.

	Range of Bid Prices		
Fiscal Year Ended September 30,	**High**	**Low**	**Cash Dividends Declared**
2008			
First Quarter	$ 33.35	$ 26.02	$ 0.3125
Second Quarter	31.43	27.25	0.3125
Third Quarter	29.25	27.13	0.3125
Fourth Quarter	32.50	26.68	0.3125
2007			
First Quarter	$ 27.80	$ 24.77	$ 0.305
Second Quarter	28.70	24.84	0.305
Third Quarter	29.01	27.01	0.305
Fourth Quarter	28.70	25.88	0.305

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Summary of Gas Sales and Statistics

Years Ended September 30,	**2008**	**2007**	**2006**	**2005**	**2004**
REVENUES:					
Residential Sales	$ 52,927,761	$ 50,791,195	$ 52,274,204	$ 49,332,645	$ 42,826,979
Commercial Sales	36,507,326	34,566,385	36,159,320	33,059,542	27,154,959
Interruptible Sales	1,509,193	1,379,870	3,054,240	3,029,697	1,234,144
Transportation Gas Sales	2,428,656	2,254,594	2,067,929	2,110,002	2,120,506
Backup Services	3,600	3,600	3,600	62,756	51,452
Late Payment Charges	55,410	55,438	70,191	55,109	71,065
Miscellaneous Gas Utility Revenue	174,647	124,579	116,924	102,918	92,433
Other	1,030,233	725,640	844,464	848,167	601,056
Total	$ 94,636,826	$ 89,901,301	$ 94,590,872	$ 88,600,836	$ 74,152,594
NET INCOME					
Continuing Operations	$ 4,257,824	$ 3,765,669	$ 2,961,802	$ 2,916,798	$ 1,627,165
Discontinued Operations	(36,690)	40,540	549,729	590,108	11,306,848
Net Income	$ 4,221,134	$ 3,806,209	$ 3,511,531	$ 3,506,906	$ 12,934,013
DTH DELIVERED:					
Residential	3,557,249	3,778,194	3,588,364	3,987,368	4,281,320
Commercial	2,785,701	2,886,403	2,793,988	2,859,471	2,937,469
Interruptible	128,875	138,176	278,535	321,860	153,714
Transportation Gas	2,779,429	2,735,456	2,853,500	3,202,923	3,391,620
Backup Service	0	0	0	5,531	5,530
Total	9,251,254	9,538,229	9,514,387	10,377,153	10,769,653
HEATING DEGREE DAYS	3,624	3,735	3,714	3,783	3,917
NUMBER OF CUSTOMERS:					
Natural Gas					
Residential	50,630	50,371	49,649	49,178	48,215
Commercial	5,026	5,017	4,948	4,939	4,903
Interruptible and Interruptible Transportation Service	33	32	32	36	36
Total	55,689	55,420	54,629	54,153	53,154
GAS ACCOUNT (DTH):					
Natural Gas Available	9,528,890	9,744,431	9,703,011	10,546,259	11,061,144
Natural Gas Deliveries	9,251,254	9,538,229	9,514,387	10,377,153	10,769,653
Storage - LNG	122,874	65,279	98,936	89,896	117,378
Company Use And Miscellaneous	45,180	28,862	36,321	47,568	52,440
System Loss	109,582	112,061	53,367	31,642	121,673
Total Gas Available	9,528,890	9,744,431	9,703,011	10,546,259	11,061,144
TOTAL ASSETS	$ 118,127,714	$ 116,332,455	$ 114,662,572	$ 113,563,416	$ 114,972,556
LONG-TERM OBLIGATIONS	$ 23,000,000	$ 23,000,000	28,000,000	28,000,000	24,000,000

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RGC Resources, Inc. and Subsidiaries

Consolidated Financial Statements

for the Years Ended September 30, 2008

and 2007, and Report of Independent

Registered Public Accounting Firm

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RGC RESOURCES, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RGC Resources, Inc.

Roanoke, Virginia

We have audited the accompanying consolidated balance sheets of RGC Resources, Inc. and Subsidiaries (the Company) as of September 30, 2008 and 2007, and the related consolidated statements of income and comprehensive income, stockholders equity, and cash flows for the years then ended. The Company s management is responsible for these financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of RGC Resources, Inc. and Subsidiaries as of September 30, 2008 and 2007, and the consolidated results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

CERTIFIED PUBLIC ACCOUNTANTS

319 McClanahan Street, S.W.

Roanoke, Virginia

November 7, 2008

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2008 AND 2007

	2008	2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 875,436	$ 1,408,317
Short-term investments	500,000	
Accounts receivable, less allowance for doubtful accounts of $63,791 in 2008 and $46,710 in 2007	5,086,790	4,447,928
Note receivable	87,000	
Materials and supplies	553,604	515,722
Gas in storage	26,122,686	19,156,833
Assets available for sale		12,825,344
Prepaid income taxes	1,479,693	1,649,788
Deferred income taxes	2,187,795	1,001,162
Under-recovery of gas costs	1,013,087	
Other	505,761	455,445
Total current assets	38,411,852	41,460,539
UTILITY PROPERTY:		
In service	113,533,184	108,348,844
Accumulated depreciation and amortization	(39,038,120)	(36,424,831)
In service, net	74,495,064	71,924,013
Construction work in progress	1,113,008	663,256
Utility plant, net	75,608,072	72,587,269
OTHER ASSETS:		
Note receivable	1,213,000	
Regulatory assets	2,762,241	2,154,145
Other	132,549	130,502
Total other assets	4,107,790	2,284,647
TOTAL ASSETS	$ 118,127,714	$ 116,332,455

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2008 AND 2007

	2008	2007
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$	$ 5,000,000
Borrowings under lines-of-credit	13,960,000	4,808,000
Dividends payable	690,538	667,245
Accounts payable	8,215,319	6,457,602
Customer credit balances	4,237,043	4,308,415
Income taxes payable	3,206	
Customer deposits	1,522,480	1,439,765
Accrued expenses	2,111,614	2,106,222
Liabilities of assets available for sale		7,558,605
Over-recovery of gas costs		567,295
Fair value of marked-to-market transactions	875,487	86,025
Total current liabilities	31,615,687	32,999,174
LONG-TERM DEBT, excluding current maturities	23,000,000	23,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	2,608,995	2,499,345
Regulatory cost of retirement obligations	6,843,338	6,043,088
Benefit plan liabilities	4,768,785	3,855,292
Deferred income taxes	5,471,667	5,442,563
Deferred investment tax credits	96,184	127,760
Total deferred credits and other liabilities	19,788,969	17,968,048
COMMITMENTS AND CONTINGENCIES (Notes 10 and 11)		
CAPITALIZATION:		
Stockholders Equity:		
Common stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 2,209,471 and 2,186,143 shares in 2008 and 2007, respectively	$ 11,047,355	$ 10,930,715
Preferred stock, no par; authorized 5,000,000 shares; no shares issued or outstanding in 2008 and 2007		
Capital in excess of par value	15,990,961	15,466,756
Retained earnings	17,909,134	16,443,017
Accumulated other comprehensive loss	(1,224,392)	(475,255)
Total stockholders equity	43,723,058	42,365,233
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 118,127,714	$ 116,332,455

(Concluded)

See notes to consolidated financial statements.

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

	2008	2007
OPERATING REVENUES:		
Gas utilities	$ 93,606,593	$ 89,175,661
Other	1,030,233	725,640
Total operating revenues	94,636,826	89,901,301
COST OF SALES:		
Gas utilities	68,283,129	64,342,382
Other	440,085	337,143
Total cost of sales	68,723,214	64,679,525
GROSS MARGIN	25,913,612	25,221,776
OTHER OPERATING EXPENSES:		
Operations	10,107,242	10,624,555
Maintenance	1,470,212	1,419,830
General taxes	1,167,293	1,130,522
Depreciation and amortization	4,330,839	4,088,590
Total other operating expenses	17,075,586	17,263,497
OPERATING INCOME	8,838,026	7,958,279
OTHER INCOME (EXPENSE), Net	34,622	(24,758)
INTEREST EXPENSE	2,033,082	1,931,444
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	6,839,566	6,002,077
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	2,581,742	2,236,408
INCOME FROM CONTINUING OPERATIONS	4,257,824	3,765,669
DISCONTINUED OPERATIONS:		
Income (loss) from discontinued operations, net of income tax expense (benefit) of ($14,628) and $835,836, respectively	(36,690)	40,540
NET INCOME	4,221,134	3,806,209
OTHER COMPREHENSIVE LOSS, NET OF TAX	(749,137)	(50,542)
COMPREHENSIVE INCOME	$ 3,471,997	$ 3,755,667

(Continued)

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

	2008	**2007**
BASIC EARNINGS PER COMMON SHARE:		
Income from continuing operations	$ 1.94	$ 1.74
Discontinued operations	(0.02)	0.02
Net income	$ 1.92	$ 1.76
DILUTED EARNINGS PER COMMON SHARE:		
Income from continuing operations	$ 1.93	$ 1.73
Discontinued operations	(0.02)	0.02
Net income	$ 1.91	$ 1.75
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:		
Basic	2,201,263	2,162,803
Diluted	2,211,226	2,173,258

(Concluded)

See notes to consolidated financial statements.

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders Equity
BALANCE September 30, 2006	$ 10,692,975	$ 14,521,812	$ 15,282,909	$ (2,828)	$ 40,494,868
Net income			3,806,209		3,806,209
Losses on hedging activities, net of tax				(50,542)	(50,542)
Adoption of SFAS No. 158				(421,885)	(421,885)
Cash dividends declared ($1.22 per share)			(2,646,101)		(2,646,101)
Issuance of common stock (47,548 shares)	237,740	944,944			1,182,684
BALANCE September 30, 2007	$ 10,930,715	$ 15,466,756	$ 16,443,017	$ (475,255)	$ 42,365,233
Net income			4,221,134		4,221,134
Losses on hedging activities, net of tax				(466,300)	(466,300)
Change in net loss and transition obligation of defined benefit plans				(282,837)	(282,837)
Cash dividends declared ($1.25 per share)			(2,755,017)		(2,755,017)
Issuance of common stock (23,328 shares)	116,640	524,205			640,845
BALANCE September 30, 2008	$ 11,047,355	$ 15,990,961	$ 17,909,134	$ (1,224,392)	$ 43,723,058

See notes to consolidated financial statements.

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income from continuing operations	$ 4,257,824	$ 3,765,669
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	4,526,670	4,301,102
Cost of removal of utility plant, net	(202,843)	(252,931)
Loss on disposal of property	7,304	
Change in over/under-recovery of gas costs	(1,542,532)	(3,027,101)
Deferred taxes and investment tax credits	(730,442)	2,003,043
Other noncash items, net	28,329	18,201
Changes in assets and liabilities which provided (used) cash:		
Accounts receivable and customer deposits, net	(556,147)	304,787
Inventories and gas in storage	(7,003,735)	813,282
Other current assets	310,119	(832,712)
Accounts payable, customer credit balances and accrued expenses, net	1,403,231	(1,463,285)
Total adjustments	(3,760,046)	1,864,386
Net cash provided by continuing operating activities	497,778	5,630,055
Net cash provided by (used in) discontinued operations	(277,913)	991,317
Net cash provided by operating activities	219,865	6,621,372
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for utility property	(6,539,369)	(6,004,190)
Proceeds from disposal of utility property	17,540	12,340
Proceeds from sale of Bluefield Operations	3,855,323	
Purchase of short-term investments	(500,000)	
Net cash used in continuing investing activities	(3,166,506)	(5,991,850)
Net cash used in discontinuted investing activities	(12,360)	(204,107)
Net cash used in investing activities	(3,178,866)	(6,195,957)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of long-term debt	(5,000,000)	
Net borrowings under line-of-credit agreements	9,152,000	1,455,000
Proceeds from issuance of common stock	640,845	1,182,684
Cash dividends paid	(2,731,725)	(2,621,923)
Net cash provided by continuing financing activities	2,061,120	15,761
Net cash provided by (used in) discontinued financing activities	365,000	(523,000)
Net cash provided by (used in) financing activities	2,426,120	(507,239)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(532,881)	(81,824)

CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,408,317	1,490,141
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 875,436	$ 1,408,317

(Continued)

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RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

	2008	**2007**
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION:		
Cash paid during the year for:		
Interest	$ 2,188,420	$ 2,335,713
Income taxes, net of refunds	$ 3,094,944	$ 1,952,794

Non-cash transactions:

A note in the amount of $1,300,000 was received as partial payment for the sale of the assets of the Bluefield division of Roanoke Gas Company.

(Concluded)

See notes to consolidated financial statements.

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RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2008 AND 2007

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General RGC Resources, Inc. is an energy services company engaged in the sale and distribution of natural gas. The consolidated financial statements include the accounts of RGC Resources, Inc. and its wholly owned subsidiaries (Resources or the Company); Roanoke Gas Company (Roanoke Gas); Diversified Energy Company; and RGC Ventures, Inc. of Virginia, operating as Application Resources. Roanoke Gas is a natural gas utility, which distributes and sells natural gas to approximately 55,700 residential, commercial and industrial customers within its service areas in Roanoke, Virginia and the surrounding areas. The Company s business is seasonal in nature and weather dependent as a majority of natural gas sales are for space heating during the winter season. Roanoke Gas is regulated by the Virginia State Corporation Commission (SCC or Virginia Commission). Application Resources provides information system services to software providers in the utility industry. Diversified Energy Company is currently inactive.

Resources has only one reportable segment as defined under Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information*. All intercompany transactions have been eliminated in consolidation.

Effective October 31, 2007, Resources sold all of the capital stock of Bluefield Gas Company (Bluefield Gas) and Roanoke Gas sold the natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia (Bluefield division of Roanoke Gas Company). See footnote 2 for additional information on the sale and corresponding discontinued operations.

Rate Regulated Basis of Accounting The Company s regulated operations follow the accounting and reporting requirements of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities). In the event that the provisions of SFAS No. 71 no longer applied to any or all regulated assets or liabilities, the Company would write off such amounts which would have an impact on net income for the period.

Regulatory assets and liabilities included in the Company s consolidated balance sheets as of September 30, 2008 and 2007 are as follows:

	September 30	
	2008	2007
Regulatory assets:		
Under-recovery of gas costs	$ 1,013,087	$
Premium on early retirement of debt	217,701	248,077
Benefit plan assets	2,731,674	1,906,068
Other	11,945	11,945
Total regulatory assets	$ 3,974,407	$ 2,166,090
Regulatory liabilities:		
Over-recovery of gas costs	$	$ 567,295
Asset retirement obligation	2,608,995	2,499,345
Regulatory cost of retirement obligations	6,843,338	6,043,088
Other		330
Total regulatory liabilities	$ 9,452,333	$ 9,110,058

Regulatory assets are included in Under-recovery of gas costs , Other current assets and Regulatory assets . Regulatory liabilities are included in Over-recovery of gas costs , Regulatory cost of retirement obligations and Asset retirement obligations . As of September 30, 2008, the Company had regulatory assets in the amount of $2,731,674 on which the Company does not earn a return during the recovery period. These assets pertain to the net funded position of the Company s benefit plans related to the regulated operations. As such, the amortization period is not specifically defined.

Utility Plant and Depreciation Utility plant is stated at original cost. The cost of additions to utility plant includes direct charges and overhead. The cost of depreciable property retired is charged to accumulated depreciation. The cost of asset removals, less salvage, is charged to regulatory cost of retirement obligations or asset retirement obligations as explained in footnote 13.

Maintenance, repairs, and minor renewals and betterments of property are charged to operations and maintenance.

Provisions for depreciation are computed principally at composite straight-line rates. The composite weighted-average depreciation rates were 4.12% of average depreciable property for the years ended September 30, 2008 and 2007. The annual composite rates for utility property are determined by periodic depreciation studies that are approved by the SCC. The Virginia Commission requires Roanoke Gas to conduct a depreciation study every five years and propose new depreciation rates for approval. The results of Roanoke Gas last depreciation study were placed into effect January 1, 2004.

The composite rates are comprised of two components, one based on average service life and one based on cost of retirement. Therefore, the Company accrues the estimated cost of retirement of long-lived assets through depreciation expense. Retirement costs are not a legal obligation as

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defined by SFAS No. 143 but rather the result of cost-based regulation and are accounted for under the provisions of SFAS No. 71. Therefore, such amounts are classified as a regulatory liability. See footnote 13 regarding legal obligations related to asset retirements.

The Company reviews long-lived assets and certain identifiable intangibles for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These reviews have not identified a material effect on results of operations or financial condition.

Cash, Cash Equivalents and Short-Term Investments From time to time, the Company will have on deposit at banks balances in excess of the amount insured by the Federal Deposit Insurance Corporation (FDIC). The Company has not experienced any losses on these accounts and does not consider these amounts to be at credit risk. As of September 30, 2008, the Company had approximately $486,000 in bank deposits in excess of the FDIC insurance limits of $100,000, which were raised to $250,000 subsequent to year end. For purposes of the consolidated statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Customer Receivables and Allowance for Doubtful Accounts The accounts receivable consist of amounts billed to customers for natural gas sales and related services. The Company provides an estimate for losses on these receivables by utilizing historical information, current account balances, account aging and current economic conditions. Customer accounts are charged off annually when deemed uncollectible or when turned over to a collection agency for action.

A reconciliation of changes in the allowance for doubtful accounts is as follows:

	Years Ended September 30	
	2008	**2007**
Balances, beginning of year	$ 46,710	$ 26,584
Additions charged to bad debt expense	197,272	120,671
Recoveries of accounts written off	199,210	294,887
Accounts written off	(379,401)	(395,432)
Balances, end of year	$ 63,791	$ 46,710

Inventories Inventories, consisting of natural gas in storage and materials and supplies, are recorded at average cost. Injections into storage are priced at the purchase cost at the time of injection and withdrawals from storage are priced at the weighted average price in storage. Materials and supplies are removed from inventory at average cost.

Unbilled Revenues The Company bills its natural gas customers on a monthly cycle basis; however, the billing cycle period for most customers does not coincide with the accounting periods used for financial reporting and, therefore, an accrual is made to estimate natural gas delivered to customers not yet billed during the accounting period. The Company recognizes revenue when gas is delivered. The amounts of unbilled revenue receivable included in accounts receivable on the consolidated balance sheets at September 30, 2008 and 2007 were $1,475,406 and $1,287,362, respectively.

Income Taxes Income taxes are accounted for using the asset and liability method. Under the asset and liability method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of

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existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the years in which those temporary differences are expected to be recovered or settled. A valuation allowance against deferred tax assets is provided if it is more likely than not the deferred tax asset will not be realized. The Company and its subsidiaries file a consolidated income tax return.

Debt Expenses Debt issuance expenses are being amortized over the lives of the debt instruments.

Over/Under-Recovery of Natural Gas Costs Pursuant to the provisions of the Company s Purchased Gas Adjustment (PGA) clause, increases or decreases in natural gas costs incurred by regulated operations, including gains and losses on derivative hedging instruments, are passed through to customers. Accordingly, the difference between actual costs incurred and costs recovered through the application of the PGA is reflected as a regulatory asset or liability. At the end of the deferral period, the balance of the net deferred charge or credit is amortized over an ensuing 12-month period as amounts are reflected in customer billings.

Use of Estimates The preparation of financial statements in conformity with Generally Accepted Accounting Principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications Certain prior period amounts have been reclassified to conform to current year presentation. Specifically, the Company reclassified the regulatory assets contained in other non-current assets into a separate line item under the Other Assets section of the Balance Sheet. The reclassification did not impact income or equity.

Earnings Per Share Basic earnings per share and diluted earnings per share are calculated by dividing net income by the weighted average common shares outstanding during the period and the weighted average common shares outstanding during the period plus dilutive potential common shares, respectively. Dilutive potential common shares are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all options are used to repurchase common stock at market value. The amount of shares remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities. A reconciliation of the weighted average common shares to diluted average common shares is provided below:

	Years Ended September 30	
	2008	**2007**
Weighted average common shares	2,201,263	2,162,803
Effect of dilutive securities:		
Options to purchase common stock	9,963	10,455
Diluted average common shares	2,211,226	2,173,258

Business and Credit Concentrations The primary business of the Company is the distribution of natural gas to residential, commercial and industrial customers in its service territories.

No regulated sales to individual customers accounted for more than 5% of total revenue in any period or amounted to more than 5% of total accounts receivable.

Roanoke Gas currently holds the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia service area. These franchises are effective through January 1, 2016. Certificates of public convenience and necessity in Virginia are exclusive and are intended for perpetual duration.

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Roanoke Gas is served directly by two primary pipelines. These two pipelines provide 100% of the natural gas supplied to the Company s customers. Depending upon weather conditions and the level of customer demand, failure of one or both of these transmission pipelines could have a major adverse impact on the Company.

Derivative and Hedging Activities SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted, requires the recognition of all derivative instruments as assets or liabilities in the Company s balance sheet and measurement of those instruments at fair value.

The Company s risk management policy allows management to enter into derivatives for the purpose of managing commodity and financial market risks of its business operations. The Company s risk management policy specifically prohibits the use of derivatives for speculative purposes. The key market risks that RGC Resources, Inc. hedges against include the price of natural gas and the cost of borrowed funds.

The Company enters into collars, swaps and caps for the purpose of hedging the price of natural gas in order to provide price stability during the winter months. The fair value of these instruments is recorded in the balance sheet with the offsetting entry to either under-recovery of gas costs or over-recovery of gas costs. Net income and other comprehensive income are not affected by the change in market value as any cost incurred or benefit received from these instruments is recoverable or refunded through the PGA. At September 30, 2008, the Company has collar agreements outstanding for the winter period to hedge 370,000 decatherms of natural gas with a fair value liability of $37,850.

The Company also entered into an interest rate swap related to the $15,000,000 note issued in November 2005. The swap essentially converted the floating rate note based on LIBOR into fixed rate debt with a 5.74% interest rate. The swap qualifies as a cash flow hedge with changes in fair value reported in other comprehensive income.

No derivative instruments were deemed to be ineffective as defined under SFAS No. 133 for any period.

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Other Comprehensive Income A summary of other comprehensive income and financial instrument activity including the effect of adopting SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*, is provided below:

	Interest Rate Swap	Natural Gas Derivative	Defined Benefit Plans	Total
Accumulated Comprehensive Loss - 9/30/06	$ (2,828)	$	$	$ (2,828)
Other Comprehensive Loss - Year Ended September 30, 2007:				
Unrealized losses	$ (37,233)	$	$	$ (37,233)
Income tax benefit	14,134			14,134
Net unrealized losses	(23,099)			(23,099)
Transfer of realized gains to income	(44,233)			(44,233)
Income tax expense	16,790			16,790
Net transfer of realized gains to income	(27,443)			(27,443)
Net other comprehensive loss	$ (50,542)	$	$	$ (50,542)
Adoption of SFAS No. 158			(421,885)	(421,885)
Accumulated Comprehensive Loss - 9/30/07	$ (53,370)	$	$ (421,885)	$ (475,255)

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	Interest Rate Swap	Natural Gas Derivative	Defined Benefit Plans	Total
Other Comprehensive Loss - Year Ended September 30, 2008:				
Unrealized losses	$ (994,914)	$	$	$ (994,914)
Income tax benefit	377,669			377,669
Net unrealized losses	(617,245)			(617,245)
Transfer of realized losses to income	243,302			243,302
Income tax benefit	(92,357)			(92,357)
Net transfer of realized gains to income	150,945			150,945
Defined Benefit Plans under SFAS No. 158:				
Unrecognized net loss arising during the period			(503,411)	(503,411)
Income tax benefit			191,296	191,296
Net unrecognized loss arising during the period			(312,115)	(312,115)
Loss reclassified to income				
Income tax expense				
Net loss reclassified to income				
Amortization of transition obligation			47,223	47,223
Income tax benefit			(17,945)	(17,945)
Net amortization of transition obligation			29,278	29,278
Net other comprehensive loss	$ (466,300)	$	$ (282,837)	$ (749,137)
Accumulated comprehensive loss - 9/30/08	$ (519,670)	$	$ (704,722)	$ (1,224,392)
Fair value of derivatives - 9/30/07	$ (86,025)	$	$	$ (86,025)
Fair value of derivatives - 9/30/08	$ (837,637)	$ (37,850)	$	$ (875,487)

New Accounting Standards In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109.* This statement clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The recognition threshold is based upon whether it is more-likely-than-not that a tax position taken by an enterprise will be sustained upon examination. The measurement attribute of a more-likely-than-not tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. On

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October 1, 2007, the Company adopted FASB Interpretation No. 48. The adoption of FIN 48 did not result in a material impact on the Company s financial position, results of operations or cash flows.

On September 30, 2007, the Company adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R.* This statement required an employer to recognize the overfunded or underfunded status of defined benefit pensions and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. The adoption of SFAS No. 158 resulted in the Company recording an additional benefit liability of $2,586,528 associated with the net underfunded positions of its defined benefit pension plan and post-retirement benefit plan. The Company also recorded a regulatory asset of $1,906,068 associated with the regulated operations of Roanoke Gas in accordance with the provisions of SFAS No. 71 whereby the Company believes that it will continue to be able to recover the change in funded status of the plans through future rates. The Company also recognized other comprehensive loss of $421,885, net of tax, for those liabilities not associated with the regulated operations. SFAS No. 158 also requires an employer to measure the funded status of each plan as of the Company s fiscal year end. The Company currently uses a June 30 measurement date for its benefit plans. The company will adopt the change in measurement date provision in the first quarter ending December 31, 2008. The change in measurement date will eliminate the three month lag in recognizing expense between the measurement date and the end of the Company s fiscal year. The Company expects to record an adjustment to retained earnings, net of tax, of $44,931 for the effect of the change in measurement date on unregulated operations and a regulatory asset in the amount of $177,284 for the portion attributable to the regulated operations of Roanoke Gas Company. The Company is currently requesting SFAS No. 71 treatment to defer this amount and provide for a three year amortization in the current rate filing before the SCC.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value methods. This statement does not require any new fair value measurements. Instead, it provides for increased consistency and comparability in fair value measurements and for expanded disclosure surrounding the fair value measurements whenever other standards require (or permit) the measurement of assets or liabilities at fair value. This statement is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Accordingly, the Company will adopt SFAS No. 157 in the first quarter of its fiscal year ending September 30, 2009. The Company does not anticipate the adoption of this statement to have a material impact on its financial position, results of operations or cash flows. In February 2008, the FASB issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually.)

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits, but does not require, entities to choose to measure selected financial assets and liabilities at fair value. Although SFAS No. 159 does not eliminate the fair value disclosure requirements included in other accounting standards, it does provide for additional presentation and disclosures designed to facilitate comparisons between companies that choose different measurement attributes for similar assets and liabilities. The effective date of this statement is for fiscal years beginning after November 15, 2007. Accordingly, the Company will adopt SFAS No. 159 in the first quarter of its fiscal year ending September 30, 2009. The Company does not anticipate the adoption of this statement to have a material impact on its financial position, results of operations or cash flows.

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In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133.* The purpose of this statement is to enhance the current disclosure framework of SFAS No. 133 by requiring entities to disclose (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flow. The effective date of this statement is for fiscal years and interim periods beginning after November 15, 2008. Accordingly, the Company will adopt SFAS No. 161 no later than the second quarter ending March 31, 2009. The Company does not anticipate the adoption of this statement to have material impact on its financial position, results of operations or cash flows.

2. DISCONTINUED OPERATIONS

Effective as of October 31, 2007, Resources closed on the sale of the stock of Bluefield Gas Company (Bluefield) to ANGD, LLC, and Roanoke Gas Company completed the sale of its natural gas distribution assets located in the Town of Bluefield and the County of Tazewell, Virginia (Bluefield division of Roanoke Gas) to Appalachian Natural Gas Company (Appalachian), a subsidiary of ANGD, LLC. Resources received approximately $1,900,000 in cash from the sale of the Bluefield stock after the retirement of approximately $5,100,000 in Bluefield debt. Roanoke Gas received approximately $1,900,000 in cash and a promissory note in the amount of $1,300,000 payable by ANGD, LLC. The note has a 5-year term with a 15-year amortization schedule with annual principal payments and quarterly interest payments at a rate of 10%. The sale of the stock of Bluefield was at book value resulting in no gain or loss on the sale. The sale of assets of the Bluefield division of Roanoke Gas was equal to the book value of net plant plus 1% and the book value of accounts receivable, natural gas inventory, and certain other listed current assets. The gain on the sale of these assets was eliminated by the costs associated with completing the sale.

At the time of the sale, Bluefield and the Bluefield division of Roanoke Gas (Bluefield Operations) represented approximately 8% of Resources natural gas distribution customers. The results of operations of both Bluefield Gas and the Bluefield division of Roanoke Gas Company up to the effective date of the sale are reflected as discontinued operations in accordance with the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

In July 2006, the Company entered into an asset purchase and sale agreement for the sale of the assets relating to its Highland Energy gas marketing business. The assets sold included the gas supply contracts between Highland Energy and its customers and related business records. Under the agreement, a portion of the purchase price was deferred as realization of those revenues was subject to certain provisions. The Company met substantially all of the provisions of the agreement and recorded $160,000 revenue in final settlement of the sales contract as part of discontinued operations in 2007.

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The components of discontinued operations are summarized below:

	Years Ended September 30 2008	2007
Bluefield Operations		
Revenues	$ 457,777	$ 11,229,432
Pretax Operating Loss	(105,216)	(134,650)
Continuing Costs	53,898	773,304
Income Tax Benefit (Expense)	14,628	(745,598)
Discontinued Operations	$ (36,690)	$ (106,944)
Highland Energy		
Revenues	$	$
Gain on Sale of Assets		160,162
Pretax Operating Income		77,560
Income Tax Expense		(90,238)
Discontinued Operations	$	$ 147,484
Total		
Revenues	$ 457,777	$ 11,229,432
Gain on Sale of Assets		160,162
Pretax Operating Loss	(105,216)	(57,090)
Continuing Costs	53,898	773,304
Income Tax Benefit (Expense)	14,628	(835,836)
Discontinued Operations	$ (36,690)	$ 40,540

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The carrying amounts of the major classes of assets and liabilities subject to the sale as of September 30, 2007 were as follows:

	September 30 2007
Assets:	
Accounts receivable, net	$ 429,582
Gas in storage	3,230,624
Other current assets	90,913
Net utility plant	9,018,903
Other assets	55,322
Assets available for sale	$ 12,825,344
Liabilities:	
Accounts payable and customer credit balances	$ 1,499,604
Accrued expenses	99,821
Other current liabilities	4,800,048
Non-current liabilities	1,159,132
Liabilities of assets available for sale	$ 7,558,605

3. REGULATORY MATTERS

The SCC exercises regulatory authority over the natural gas operations of Roanoke Gas Company. Such regulation includes the approval of rates to be charged to customers for natural gas service.

On November 1, 2007, Roanoke Gas Company placed into effect new base rates to provide for approximately $700,000 in additional annual revenues, subject to refund. The Company received the final order from the SCC on May 22, 2008 approving rates, which provided for approximately $416,000 in additional annual revenues. In June 2008, the Company completed its refund of rates billed in excess of the amount authorized by the final order, including interest on the excess amount.

On September 16, 2008, the Company filed a request for an expedited rate increase with the SCC. The request was for an increase of approximately $1,198,000 in annual non-gas revenues. Under an expedited rate request, the Company was able to place the increased rates into effect for service rendered on and after November 1, 2008, subject to refund pending a final order by the SCC. The hearing on the request for rate increase is scheduled for the end of March 2009, with a final order expected some time after that date.

4. BORROWINGS UNDER LINES-OF-CREDIT

The Company has available unsecured lines-of-credit with a bank which will expire March 31, 2009. The Company anticipates being able to extend or replace the lines-of-credit. The Company s available unsecured lines-of-credit vary during the year to accommodate its seasonal borrowing demands. Generally, the Company s borrowing needs are at their lowest in spring, increase during the summer and fall due to gas storage purchases and construction expenditures and reach their maximum levels in winter. Available limits under these agreements for the remaining term are as follows:

Effective	Available Lines of Credit
September 30, 2008	$ 27,000,000
November 16, 2008	29,000,000

February 16, 2009	16,000,000

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A summary of the lines-of-credit follows:

	2008	2007
Lines-of-credit at year-end	$ 27,000,000	$ 17,000,000
Outstanding balance at year-end	13,960,000	4,808,000
Highest month-end balances outstanding	13,960,000	8,421,000
Average month-end balances	5,178,000	2,715,000
Average rates of interest during year	4.25%	5.83%
Average rates of interest on balances outstanding at year-end	4.43%	5.62%

5. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30	
	2008	2007
First Mortgage notes payable, at 7.804%, due July 1, 2008	$	$ 5,000,000
Unsecured senior notes payable, at 7.66%, with provision for retirement of $1,600,000 each year beginning December 1, 2014 through December 1, 2018	8,000,000	8,000,000
Unsecured note payable, with variable interest rate based on 30-day LIBOR (3.70% at September 30, 2008) plus 69 basis point spread, with provision for retirement on December 1, 2010	15,000,000	15,000,000
Total long-term debt	23,000,000	28,000,000
Less current maturities		(5,000,000)
Total long-term debt	$ 23,000,000	$ 23,000,000

The above debt obligations contain various provisions, including a minimum interest charge coverage ratio, limitations on debt as a percentage of total capitalization and a provision restricting the payment of dividends, primarily based on the earnings of the Company and dividends previously paid. The Company was in compliance with these provisions at September 30, 2008 and 2007. At September 30, 2008, approximately $14,900,000 of retained earnings was available for dividends.

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The Company may request an extension of the maturity date of the unsecured variable rate note anytime subsequent to the first anniversary subject to approval by the Bank. The Company also has an interest rate swap related to the $15,000,000 note. The swap essentially converted the variable rate note into fixed rate debt with a 5.74% interest rate.

The Company retired the $5,000,000 first mortgage note on July 1, 2008. Prior to September 30, Roanoke Gas Company filed an application with the SCC requesting to refinance the $5,000,000 with a long-term note. On October 17, 2008, the SCC approved Roanoke Gas request to refinance the $5,000,000 note. On October 31, 2008, the Company issued a $5,000,000 variable rate note at LIBOR plus 125 basis points, and simultaneously entered into an interest rate swap to convert the variable rate note into a fixed rate debt with a 5.79% interest rate. The new note places a restriction on the payment of dividends that, if in place at September 30, 2008, would have limited retained earnings available for dividends to approximately $11,400,000.

The aggregate annual maturities of long-term debt for the next five years ending September 30 and thereafter are as follows:

Years Ended September 30	**Maturities**
2009	$
2010	
2011	15,000,000
2012	
2013	
Thereafter	8,000,000
Total	$ 23,000,000

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6. INCOME TAXES

The details of income tax expense (benefit) from continuing operations are as follows:

	Years Ended September 30 2008	2007
Current income taxes:		
Federal	$ 2,385,856	$ 806,956
State	508,082	113,461
Total current income taxes	2,893,938	920,417
Deferred income taxes:		
Federal	(192,741)	1,100,072
State	(89,288)	246,407
Total deferred income taxes	(282,029)	1,346,479
Amortization of investment tax credits	(30,167)	(30,488)
Total income tax expense	$ 2,581,742	$ 2,236,408

Income tax expense for the years ended September 30, 2008 and 2007 differed from amounts computed by applying the U.S. Federal income tax rate of 34 percent to earnings before income taxes as a result of the following:

	Years Ended September 30 2008	2007
Income before income taxes	$ 6,839,566	$ 6,002,077
Income tax expense computed at the federal statutory rate	$ 2,325,452	$ 2,040,706
State income taxes, net of federal income tax benefit	276,404	237,513
Amortization of investment tax credits	(30,167)	(30,488)
Other, net	10,053	(11,323)
Total income tax expense	$ 2,581,742	$ 2,236,408

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The tax effects of temporary differences that give rise to the deferred tax assets and deferred tax liabilities are as follows:

	September 30	
	2008	2007
Deferred tax assets:		
Allowance for uncollectibles	$ 24,215	$ 18,838
Accrued pension and post-retirement medical benefits	1,888,963	1,454,905
Accrued vacation	195,733	187,173
Over-recovery of gas costs		215,346
Costs of gas held in storage	933,035	853,169
Accrued gas costs	676,389	
Deferred compensation	417,224	338,891
Interest rate swap	317,967	32,655
Other	184,318	169,515
Total deferred tax assets	4,637,844	3,270,492
Deferred tax liabilities:		
Utility plant	7,551,517	7,054,425
Accrued gas costs		51,630
Sale of Bluefield Gas stock		605,838
Under-recovery of gas costs	370,199	
Total deferred tax liabilities	7,921,716	7,711,893
Net deferred tax liability	$ 3,283,872	$ 4,441,401

FIN 48 provides for the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recognized in the financial statements. The Company has evaluated its tax positions and accordingly has determined that an unrecognized tax benefit in the amount of $23,276 existed as of October 1, 2007. The unrecognized tax benefit is associated with a timing difference and therefore would not impact the effective tax rate for the periods presented. Interest associated with uncertain tax positions is classified as interest expense in the financial statements. Penalties are classified under other income (expense).

The Company files federal income tax returns and state income tax returns in Virginia and West Virginia. An audit of the Company s federal income tax return was completed for the year ended September 30, 2006. The federal returns and the state returns for both Virginia and West Virginia for the tax years ended prior to September 30, 2005 are no longer subject to examination.

7. EMPLOYEE BENEFIT PLANS

The Company sponsors both a noncontributory defined benefit pension plan and a postretirement benefit plan (Plans). The defined benefit pension plan covers substantially all employees and benefits fully vest after five years of credited service. Benefits paid to retirees are based on age at retirement, years of service and average compensation. The postretirement benefit plan provides certain healthcare and life insurance benefits to retired employees who meet specific age and service requirements.

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On September 30, 2007, the Company adopted SFAS No. 158. This Standard retains the previous periodic expense calculation on an actuarial basis under the provisions of SFAS No. 87, *Employers Accounting for Pensions* and SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*. In addition, this statement also requires an employer to recognize the overfunded or underfunded status of defined benefit pensions and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. For pension plans, the benefit obligation is the projected benefit obligation, and for other postretirement plans, the benefit obligation is the accumulated benefit obligation. The Company established a regulatory asset for the portion of the obligation expected to be recovered in rates in future periods in accordance with SFAS No. 71. The portion of the obligation attributable to the unregulated operations of the holding company parent is recognized in comprehensive income. SFAS No. 158 also requires an employer to measure the funded status of each plan as of the Company s fiscal year end for fiscal years ending after December 31, 2008. The effect of the change in measurement date is reflected in footnote 1.

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The following tables set forth the benefit obligation, fair value of plan assets, and the funded status of the Plans; amounts recognized in the Company s financial statements and the assumptions used:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Accumulated benefit obligation	$ 10,437,064	$ 9,364,621	$ 8,304,632	$ 8,427,326
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 12,538,300	$ 12,102,103	$ 8,427,326	$ 8,266,411
Service cost	429,461	404,909	140,327	147,693
Interest cost	769,517	740,918	511,387	501,838
Actuarial (gain) loss	429,383	(307,353)	(339,674)	(113,471)
Benefit payments, net of retiree contributions	(411,240)	(402,277)	(434,734)	(375,145)
Benefit obligation at end of year	$ 13,755,421	$ 12,538,300	$ 8,304,632	$ 8,427,326
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 10,984,155	$ 9,248,810	$ 5,202,179	$ 4,212,556
Actual return on plan assets, net of taxes	27,412	1,312,622	(300,504)	594,768
Employer contributions	800,000	825,000	724,000	770,000
Benefit payments, net of retiree contributions	(411,240)	(402,277)	(434,734)	(375,145)
Fair value of plan assets at end of year	$ 11,400,327	$ 10,984,155	$ 5,190,941	$ 5,202,179
Reconciliation of funded status:				
Funded status	$ (2,355,094)	$ (1,554,145)	$ (3,113,691)	$ (3,225,147)
Contributions made between the measurement date and fiscal year-end		200,000	700,000	724,000
Net amount recognized in the balance sheet	$ (2,355,094)	$ (1,354,145)	$ (2,413,691)	$ (2,501,147)
Amounts recognized in the balance sheets consist of:				
Noncurrent liabilities	$ (2,355,094)	$ (1,354,145)	$ (2,413,691)	$ (2,501,147)
Amounts recognized in accumulated other comprehensive loss:				
Transition obligation, net of tax	$	$	$ 146,393	$ 175,671
Net actuarial loss, net of tax	372,501	160,387	185,828	85,827
Total amounts included in other comprehensive loss, net of tax	$ 372,501	$ 160,387	$ 332,221	$ 261,498
Amounts deferred to a regulatory asset:				
Transition obligation	$	$	$ 708,345	$ 850,014
Net actuarial loss	1,607,687	726,454	415,642	329,600
Amounts recognized as regulatory assets	$ 1,607,687	$ 726,454	$ 1,123,987	$ 1,179,614

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The Company expects that approximately $72,000, before tax, of accumulated other comprehensive loss will be recognized as a portion of net periodic benefit costs in fiscal 2009 and approximately $187,000 of amounts deferred as regulatory assets will be amortized and recognized in net periodic benefit costs in fiscal 2009.

The Company amortizes the unrecognized transition obligation over 20 years.

The following table details the actuarial assumptions used in determining the projected benefit obligations and net benefit cost of the pension and the accumulated benefit obligations and net benefit cost of the postretirement plan for 2008 and 2007.

	Pension Benefits		Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
Assumptions related to benefit obligations:				
Discount rate	6.25%	6.25%	6.25%	6.25%
Expected rate of compensation increase	5.00%	5.00%	N/A	N/A
Assumptions related to benefit costs:				
Discount rate	6.25%	6.25%	6.25%	6.25%
Expected long-term rate of return on plan assets	7.50%	7.50%	5.22%	5.39%
Expected rate of compensation increase	5.00%	5.00%	N/A	N/A

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of each plan s portfolio. This resulted in the selection of the corresponding long-term rate of return assumptions used for each plan s assets.

	Pension Benefits		Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
Components of net periodic pension cost:				
Service cost	$ 429,461	$ 404,909	$ 140,327	$ 147,693
Interest cost	769,517	740,918	511,387	501,838
Expected return on plan assets	(821,381)	(691,262)	(286,504)	(238,896)
Amortization of unrecognized transition obligation			188,892	188,892
Recognized loss		72,225		9,887
Net periodic benefit cost	$ 377,597	$ 526,790	$ 554,102	$ 609,414

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Actuarial estimates for the postretirement benefit plan assumed a weighted average annual rate increase in the per capital costs of covered health care benefits (medical trend rate) were 8% and 9% for 2008 and 2007, respectively. The rates were assumed to decrease gradually to 5% by the year 2011 and remain at that level thereafter. Assumed medical trend rates have a significant effect on the amounts reported. A 1% point change in assumed healthcare cost trend rates would have the following effects:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 90,401	$ (73,738)
Effect on accumulated postretirement benefit obligation	1,013,001	(839,389)

The Company s target and actual asset allocation in the pension and postretirement benefit plans as of June 30 were:

	Pension Plan			Postretirement Benefit Plan		
	Target	2008	2007	Target	2008	2007
Asset category:						
Equity securities	50%-70%	56%	60%	35%-65%	49%	51%
Debt securities	30%-50%	30%	34%	35%-65%	45%	41%
Other	0%-20%	14%	6%	0%-20%	6%	8%

The primary objectives of the Company s investment policy is to maintain investment portfolios that diversify risk through prudent asset allocation parameters, achieve asset returns that meet or exceed the plans actuarial assumptions, achieve asset returns that are competitive with like institutions employing similar investment strategies and meet expected future benefits. The investment policy is periodically reviewed by the Company and a third-party fiduciary for investment matters.

The Company expects to contribute $600,000 to its pension plan and $600,000 to its postretirement benefit plan in fiscal 2009.

The following table reflects expected future benefit payments.

Fiscal year ending September 30	Pension Plan	Postretirement Benefit
2009	$ 412,000	$ 488,000
2010	433,000	486,000
2011	435,000	495,000
2012	466,000	496,000
2013	515,000	507,000
2014-2018	3,088,000	2,751,000

The Company also sponsors a defined contribution plan (401k Plan) covering all employees who elect to participate. Employees may contribute from 1% to 50% of their annual compensation to the 401k Plan, limited to a maximum annual amount as set periodically by the Internal Revenue Service. The Company makes matching contributions to the 401k plan with a 100% match on the participants first 3% of contributions and 50% on the next 3% of contributions. Company matching contributions were $246,338 and $240,946 for 2008 and 2007, respectively.

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8. COMMON STOCK OPTIONS

The Company s stockholders approved the RGC Resources, Inc. Key Employee Stock Option Plan (KESOP). The KESOP provides for the issuance of common stock options to officers and certain other full-time salaried employees to acquire a maximum of 100,000 shares of the Company s common stock. The KESOP requires each option s exercise price per share to equal the fair value of the Company s common stock as of the date of the grant. As of September 30, 2008, the number of shares available for future grants under the KESOP is 2,000 shares.

SFAS No. 123R, *Share-Based Payment*, a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, eliminates the use of the intrinsic value method of accounting as prescribed under Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees.* Under APB Opinion No. 25, the Company did not recognize stock-based employee compensation expense related to its KESOP in net income as all options granted under the KESOP had an exercise price equal to the market value of the underlying common stock on the date of the grant. The Company adopted the provisions of SFAS No. 123R using the modified prospective application. Under the modified prospective application, only new grants and grants that have been modified, cancelled or have not yet vested require recognition of compensation cost. All awards granted and vested prior to the effective date remain under the provision of APB Opinion No. 25.

The aggregate number of shares under option pursuant to the KESOP are as follows:

	Number of Shares	**Weighted-Average Exercise Price**	**Option Price Per Share**
Options outstanding, September 30, 2006	44,000	$ 19.485	$16.875-$20.875
Options exercised	(12,500)	$ 19.425	
Options expired			
Options outstanding, September 30, 2007	31,500	$ 19.508	$18.100-$20.875
Options exercised	(2,000)	$ 20.875	
Options expired			
Options outstanding, September 30, 2008	29,500	$ 19.416	$18.100-$20.875

The intrinsic value of the options exercised during fiscal 2008 and 2007 were $14,251 and $86,439, respectively.

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	Options Outstanding and Exercisable			
	Shares	Remaining Life (Years)	Exercise Price	Intrinsic Value
	7,000	1.2	$ 20.875	
	7,000	2.2	19.250	
	9,000	3.2	19.360	
	6,500	4.2	18.100	
Weighted average	29,500	2.7	$ 19.416	$ 311,940

Under the terms of the KESOP, the options become exercisable six months from the grant date and expire ten years subsequent to the grant date. All options outstanding were fully vested and exercisable at September 30, 2008 and 2007. No options were granted in 2008 and 2007. The Company received $41,750 from the exercise of options in 2008.

9. OTHER STOCK PLANS

Dividend Reinvestment and Stock Purchase Plan

The Company offers a Dividend Reinvestment and Stock Purchase Plan (DRIP) to shareholders of record for the reinvestment of dividends and the purchase of additional investments of up to $40,000 per year in shares of common stock of the Company. Under the DRIP plan, the Company issued 16,715 and 28,490 shares in 2008 and 2007, respectively. As of September 30, 2008, the Company had 270,686 shares available for issuance.

Restricted Stock Plan

The Board of Directors of the Company implemented the Restricted Stock Plan for Outside Directors effective January 27, 1997. The Plan is applicable to not more than 50,000 shares of Resources common stock. Under the Plan, a minimum of 40% of the monthly retainer fee paid to each non-employee director of Resources is paid in shares of common stock (Restricted Stock). The number of shares of Restricted Stock is calculated each month based on the closing sales price of Resources common stock on the NASDAQ National Market on the first day of the month, if the first day of the month is a trading day, or if not, the first trading day prior to the first day of the month. Beginning in fiscal 1998, a participant can, subject to approval of the Board, elect to receive up to 100% of his retainer fee for the fiscal year in Restricted Stock. Such election cannot be revoked or amended during the fiscal year.

The shares of Restricted Stock of Resources issued under the Plan will vest only in the case of a participant s death, disability, retirement (including not standing for reelection to the Board), or in the event of a change in control of Resources. There is no option to take cash in lieu of stock upon vesting of shares under the Plan. The Restricted Stock may not be sold, transferred, assigned or pledged by the participant until the shares have vested under the terms of the Plan. At the time the Restricted Stock vests, a certificate for vested shares will be delivered to the participant or the participant s beneficiary.

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The shares of Restricted Stock will be forfeited to Resources by a participant s voluntary resignation during his term on the Board or removal for cause as a director. Subject to the terms of the Plan, a participant, as owner of the Restricted Stock, has all rights of a shareholder, including but not limited to, voting rights, the right to receive cash or stock dividends, and the right to participate in any capital adjustment of Resources. Resources requires that all dividends or other distributions paid on shares of Restricted Stock be automatically sequestered and reinvested on an immediate or deferred basis in additional Restricted Stock.

The Company issued a total of 4,232 shares of Restricted Stock in fiscal 2008 to its outside directors, representing $89,980 in compensation and $30,707 in dividends reinvested. The directors also received a total of 4,091 shares of Restricted Stock in fiscal 2007, representing $84,550 in compensation and $25,013 in dividends reinvested. As of September 30, 2008, the Company had 15,894 shares available for issuance under this Plan.

Stock Bonus Plan

Under the Stock Bonus Plan, executive officers are encouraged to own a position in the Company s common stock of at least 50% of the value of their annual salary. To promote this policy, the Plan provides that all officers with stock ownership positions below 50% of the value of their annual salaries must, unless approved by the Committee, receive no less than 50% of any performance bonus in the form of Company common stock. Under the Stock Bonus Plan, the Company issued 781 and 2,462 shares valued at $22,163 and $68,573, respectively, in 2008 and 2007. As of September 30, 2008, the Company had 22,998 shares available for issuance under this Plan.

10. ENVIRONMENTAL MATTER

Both Roanoke Gas Company and Bluefield Gas Company operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the late 1940s or early 1950s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. Should the Company be required to remediate either site, the Company will pursue all prudent and reasonable means to recover any related costs, including insurance claims and regulatory approval for rate case recognition of expenses associated with any work required. While the Company sold the stock of Bluefield Gas Company to ANGD, LLC, it retained ownership of the former MGP site and entered into an Indemnification and Cost Sharing Agreement with ANGD to seek rate recovery of any remediation costs through rate recovery and under any applicable insurance policies or from any third party for reimbursement to the Company for 25% of any such costs to the extent they are not otherwise recovered. If the Company incurs costs associated with a required clean-up of the Roanoke Gas Company MGP site, the Company anticipates recording a regulatory asset for such clean-up costs to be recovered in future rates.

11. COMMITMENTS

Due to the nature of the natural gas distribution business, the Company has entered into agreements with both suppliers and pipelines to contract for natural gas commodity purchases, storage capacity and pipeline delivery capacity.

The Company obtains most of its regulated natural gas supply from the asset management contract between Roanoke Gas Company and the asset manager. The Company uses an asset manager to assist in optimizing the use of its transportation, storage rights, and gas supply inventories to provide a secure and reliable source of natural gas supply.

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Under the same asset management contract mentioned above, the Company designated the asset manager as agent for their storage capacity and all gas balances in storage. The asset manager provides agency service and manages the utilization of storage assets and the corresponding withdrawals from and injections into storage. The Company retains physical ownership of storage. Under the provision of the asset management contract, the Company has an obligation to purchase its winter storage requirements during the spring and summer injection periods at market price.

The Company also has contracts for pipeline and storage capacity extending for various periods. These capacity costs and related fees are valued at tariff rates in place as of September 30, 2008. These rates may increase or decrease in the future based upon rate filings and rate orders granting a rate change to the pipeline or storage operator.

The following table reflects the financial and volumetric obligations as of September 30, 2008 for each of the next five years and thereafter.

	Fixed Price Contracts	Market Price Contracts
Fiscal Year Ending September 30,	**Pipeline and Storage Capacity**	**Natural Gas Contracts (Decatherms)**
2009	$ 9,892,482	1,907,195
2010	9,892,482	2,225,059
2011	9,892,482	317,864
2012	9,892,482	
2013	9,259,717	
Thereafter	17,398,732	

The Company purchased approximately $71,838,000 and $60,121,000 in gas under the asset management contracts in fiscal year 2008 and 2007, respectively.

The Company has historically entered into derivative financial contracts for the purpose of hedging the price of natural gas. As of September 30, 2008, the Company has contracted to hedge, through derivative collar arrangements, a set amount of decatherms of natural gas for each month in the winter period, totaling 370,000 decatherms. All decatherm amounts have a ceiling price of $12.00 per decatherm and floor prices ranging from $6.33 to $8.30 per decatherm; see *Derivative and Hedging Activities* in footnote 1 for more information.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, temporary cash investments, accounts receivable, accounts payable and borrowings under lines of credit are a reasonable estimate of fair value due to the short-term nature of these financial instruments.

The fair value of long-term debt is estimated by discounting the future cash flows of each issuance at rates currently offered to the Company for similar debt instruments of comparable maturities. The carrying amounts and approximate values for the years ended September 30, 2008 and 2007 are as follows:

	2008		2007	
	Carrying Amounts	**Approximate Fair Value**	**Carrying Amounts**	**Approximate Fair Value**
Long-term debt	$ 23,000,000	$ 23,925,711	$ 28,000,000	$ 28,934,541

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The Company has an interest rate swap related to the $15,000,000 variable rate note. The swap essentially converted the variable rate note into fixed rate debt with a 5.74% interest rate. The fair value of the interest rate swap included as a liability in the consolidated balance sheets was $837,637 and $86,025 as of September 30, 2008 and 2007, respectively. See Other Comprehensive Income in footnote 1 for more information.

Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of September 30, 2008 and 2007 are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

13. ASSET RETIREMENT OBLIGATIONS

The Company adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), as of September 30, 2006. FIN 47 requires that a liability be recognized for an asset retirement obligation which is conditional based on the occurrence of a future event even if the timing or method of settlement is uncertain. SFAS No. 143 and FIN 47 require entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost, thereby increasing the carrying amount of the underlying asset. In subsequent periods, the liability is accreted, and the capitalized cost is depreciated over the useful life of the underlying asset. Under the provisions of FIN 47, the Company recorded asset retirement obligations for its future legal obligations related to purging and capping its distribution mains and services upon retirement, although the timing of such retirements is uncertain.

The Company s composite depreciation rates include a component to provide for the cost of retirement of assets. As a result, the Company accrues estimated cost of retirement of its utility plant through depreciation expense and creates a corresponding regulatory liability in accordance with the provisions of SFAS No. 71. The costs of retirement considered in the development of the depreciation component include those costs associated with the legal liability as defined under SFAS No. 143 and FIN 47. Therefore, at the time of adoption of FIN 47, the Company reclassified a portion of its regulatory liability for cost of retirement to asset retirement obligations for the legal liability as determined above. The accretion of the asset retirement obligation is reclassified from the regulatory cost of retirement obligation. If the legal obligations would exceed the regulatory liability provided for in the depreciation rates, the Company would establish a regulatory asset for such difference with the anticipation of future recovery through rates charged to customers.

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The following is a summary of the asset retirement obligation:

	Asset Retirement Obligation
September 30, 2006	$ 2,404,839
Accretion	115,810
Additions	21,217
Retirements	(42,521)
September 30, 2007	2,499,345
Accretion	121,982
Additions	27,766
Retirements	(40,098)
September 30, 2008	$ 2,608,995

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