RGC RESOURCES INC
Form ARS
December 17, 2009

Corporate Profile

RGC Resources, Inc., provides superior customer service and shareholder value as a preferred provider of energy and diversified products and services in its selected market areas.

At RGC Resources, Inc., we re committed to our customers. In this past year we have focused on the basics of our business. Every area of our business is undergoing constant improvement from the customer service department that answers customer calls to the service team that takes care of their needs to the pipeline that delivers gas to meet energy requirements. We are constantly working to enhance our energy distribution infrastructure in anticipation of our customers future requirements.

We re planning and executing solutions before they are required.

Years Ended September 30,	**2009**	**2008**	**2007**
Operating Revenue - Natural Gas	$ 80,786,228	$ 93,606,593	$ 89,175,661
Other Revenue	$ 1,398,245	$ 1,030,233	$ 725,640
Net Income - Continuing Operations	$ 4,869,010	$ 4,257,824	$ 3,765,669
Net Loss - Discontinued Operations	$	$ (36,690)	$ 40,540
Basic Earnings Per Share - Continuing Operations	$ 2.19	$ 1.94	$ 1.74
Basic Earnings Per Share - Discontinued Operations		(0.02)	0.02
Regular Dividend Per Share - Cash	$ 1.28	$ 1.25	$ 1.22
Number of Customers - Natural Gas	56,119	55,689	55,420
Total Natural Gas Deliveries - DTH	9,260,469	9,251,254	9,538,229
Total Additions to Plant	$ 5,752,780	$ 6,539,369	$ 6,004,190

Downtown illustration adapted from an image provided courtesy of Kurt Konrad.

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)

Robert L. Wells
Vice President,
Information Technology,
Assistant Secretary and
Assistant Treasurer (1)(2)(3)(4)

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

DIRECTORS

Nancy H. Agee
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)

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)(2)

S. Frank Smith
Vice President Industrial Sales
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:

John S. D Orazio
Vice President and
Chief Operating Officer
Roanoke Gas Company
Director: (3)(4)

Howard T. Lyon
Vice President, Treasurer and
Chief Financial Officer
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)

Selected Financial Data

Years Ended September 30,	**2009**	**2008**	**2007**	**2006**	**2005**
Operating Revenues	$ 82,184,473	$ 94,636,826	$ 89,901,301	$ 94,590,872	$ 88,600,836
Gross Margin	27,075,924	25,913,612	25,221,776	23,208,272	22,206,395
Operating Income	9,844,516	8,838,026	7,958,279	6,677,500	6,395,564
Net Income - Continuing Operations	4,869,010	4,257,824	3,765,669	2,961,802	2,916,798
Net Income (Loss) - Discontinued Operations		(36,690)	40,540	549,729	590,108
Basic Earnings Per Share - Continuing Operations	$ 2.19	$ 1.94	$ 1.74	$ 1.40	$ 1.40
Basic Earnings Per Share - Discontinued Operations		(0.02)	0.02	0.26	0.29
Cash Dividends Declared Per Share	$ 1.28	$ 1.25	$ 1.22	$ 1.20	$ 1.18
Book Value Per Share	20.01	19.79	19.38	18.94	18.18
Average Shares Outstanding	2,223,727	2,201,263	2,162,803	2,120,267	2,079,851
Total Assets	118,801,892	118,127,714	116,332,455	114,662,572	113,563,416
Long-Term Debt (Less Current Portion)	28,000,000	23,000,000	23,000,000	28,000,000	28,000,000
Stockholders Equity	44,799,871	43,723,058	42,365,233	40,494,868	38,157,357
Shares Outstanding at Sept. 30	2,238,987	2,209,471	2,186,143	2,138,595	2,098,935

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 from regulatory authorities for increasing operating or gas costs; (xiii) capital market conditions and the availability of debt and equity financing to support capital expenditures; (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 sim conditional verbs such as will, would, should, can, could or 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.

Management s Discussion & Analysis

Overview

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 56,100 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 approved by the SCC.

Resources also provided the 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 Gas 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 corresponding activities of the Bluefield Operations were classified to discontinued operations in the prior year as discussed in Note 2 of the consolidated financial statements.

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

Local economic conditions, volatility in natural gas prices, and winter weather conditions, have a direct influence on the quantity of natural gas deliveries, and management believes each factor has the potential to significantly impact earnings. Economic downturns generally result in a decline in business and industrial production. For those operations that use natural gas in their production process, lower industrial production has

resulted in a reduction in natural gas usage. Under the current economic climate, the Company has experienced a 12% decline in industrial and transportation volumes from last year s levels. In addition, significant increases in natural gas commodity prices could have a significant affect on customer usage. Currently, natural gas prices are the lowest the Company has experienced in the last few years; however, sharp increases in the price of natural gas could affect customer usage by encouraging conservation or the use of alternative fuels. Furthermore, a majority of natural gas sales are for space heating during the winter season. Consequently, during warmer winters or unevenly cold winters, customers may significantly reduce their consumption of natural gas. The effect of warmer than normal winters is mitigated by a weather normalization adjustment (WNA) factor as discussed below.

The current economic environment has had a negative impact on the local economy as construction activity has slowed significantly and industrial activity has declined. Natural gas consumption by the Company s industrial and transportation customers has declined by more than 12% from last year s levels. Much of the decline appears to be related to a reduced level of production activities by these customers; however, the Company anticipates natural gas deliveries to improve as the economy recovers. One of the Company s transportation customers closed its operations during fiscal 2009 as a result of the economy, which accounted for approximately 50,000 decatherms in deliveries, or $75,000 in margin, annually. A prolonged economic downturn could result in additional closings or lead to further reductions in industrial activity. In addition, growing job losses and deteriorating economic conditions may lead to an increase in customer payment delays and higher bad debt expense. Recent low natural gas commodity prices have reduced customer billings during the current period, which contributed to bad debt expense remaining consistent with prior year amounts. Management continues to closely monitor accounts receivable activity.

Volatility in natural gas prices presents other issues for the Company. The commodity price of natural gas has declined from its peak of more than $13.00 per decatherm during fiscal 2008 to under $4.00 a decatherm in September 2009. Currently, futures prices for natural gas on the NYMEX (New York Mercantile Exchange) range between $5.00 and $7.00 per decatherm over the next 12 months, implying relative stability in prices. A strong economic recovery that increases demand for natural gas or unfavorable environmental legislation could escalate natural gas prices and make natural gas a less attractive energy source and increase the level of bad debts. Supply disruptions, extended periods of cold weather or volatility in the commodities market could also serve to increase natural gas costs.

Because the SCC authorizes billing rates for the utility operations of Roanoke Gas based on normal 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 significant portion of the risk associated with warmer than normal winter weather by the inclusion of a WNA factor as part of its rate structure. This factor allows the Company to recover revenues equivalent to the margin that would be realized at approximately 6% warmer than the most recent 30-year temperature average for the Company s service area or refund revenues for any margin realized for weather greater than approximately 6% colder than the 30-year average. 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. For the WNA period ending March 31, 2009, the Company did not record a WNA adjustment as the number of heating degree-days fell within the 6% weather band during the measurement period. In comparison, the Company recorded approximately $363,000 in additional revenues for the WNA period ended March 31, 2008 for weather that was 11% warmer than the 30-year average. Effective with the WNA period beginning in April 2009, the SCC approved the Company s request to reduce the weather band for determining WNA from approximately 6% above and below the most recent 30 year average to 3% above and below the most recent 30 year average.

The Company has an approved rate structure in place that mitigates the impact of financing costs of its natural gas inventory. Under this rate structure, Roanoke Gas recognizes revenue for the financing costs or carrying costs of its investment in natural gas inventory. The carrying cost revenue factor applied to inventory is based on the Company s weighted average cost of capital including interest rates on short-term and long-term debt and the Company s authorized return on equity. 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 recognizes less carrying cost revenue as financing costs are lower. The Company recognized approximately $2,328,000 and $2,351,000 in carrying cost revenues for the years ended September 30, 2009 and 2008, respectively. The level of carrying cost revenues for fiscal 2009 was consistent with fiscal 2008; however, due to the much lower price of natural gas in storage at September 30, 2009 compared to September 30, 2008 ($6.05 per decatherm compared to $9.81 per decatherm), carrying cost revenues for fiscal 2010 are expected to be much lower than fiscal 2009, as will be the actual cost for financing inventory levels.

In the short run, as investment in natural gas inventories increases so does the level of borrowing under the Company s line-of-credit. However, as the factor used in determining the carrying cost revenues is based on the Company s weighted average cost of capital, carrying cost revenues do not directly correspond with the short-term incremental financing costs. Therefore, when inventory balances decline due to a reduction in commodity prices, net income will decline as carrying cost revenues decrease by a greater amount than short-term financing costs. The inverse occurs when inventory costs increase.

For the fiscal year ended September 30, 2009, the implementation of a non-gas rate increase and a reduction in depreciation expense due to implementation of updated depreciation rates more than offset increases in operation and maintenance expenses.

Results of Operations Continuing Operations

Fiscal Year 2009 Compared with Fiscal Year 2008

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

Year Ended September 30,	2009	2008	Increase/ (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Residential and Commercial	6,697,738	6,342,950	354,788	6%
Transportation and Interruptible	2,562,731	2,908,304	(345,573)	-12%
Total	9,260,469	9,251,254	9,215	0%
Heating Degree-Days (Unofficial)	3,914	3,624	290	8%

Operating Revenues - The table below reflects operating revenues.

Year Ended September 30,	2009	2008	Increase/ (Decrease)	Percentage
Gas Utility	$ 80,786,228	$ 93,606,593	$ (12,820,365)	-14%
Other	1,398,245	1,030,233	368,012	36%
Total Operating Revenues	$ 82,184,473	$ 94,636,826	$ (12,452,353)	-13%

Total gas utility operating revenues for the year ended September 30, 2009 (fiscal 2009) decreased by 14% from the year ended September 30, 2008 (fiscal 2008) even though total delivered volumes were nearly the same during both periods. The decrease in gas revenues is due to significantly lower gas costs. During fiscal 2008, the commodity price of gas increased significantly from March through July, with the price climbing from $8.00 to nearly $14.00 a decatherm at its peak before dropping below $8.00 a decatherm at the end of September 2008. During fiscal 2009, natural gas prices experienced a steady decline during the year with prices dropping from $8.00 at the beginning of the year to below $4.00 a decatherm by the end of fiscal 2009. For the year, the average per unit cost

of natural gas reflected in cost of sales decreased by 24%. From a volume perspective, tariff sales, consisting primarily of the more weather sensitive residential and commercial customers, increased by 6% corresponding to the 8% rise in the number of heating degree-days. Transportation and interruptible sales declined by 12%, reflecting the economic recession.

Other revenues increased by 36% primarily due to an increase in paving services provided to another local utility under an agreement in effect through the end of January 2010 and a higher level of utility consulting services.

Gross Margin - The table below reflects gross margins.

Year Ended September 30,	2009	2008	Increase/ (Decrease)	Percentage
Gas Utilities	$ 26,377,450	$ 25,323,464	$ 1,053,986	4%
Other	698,474	590,148	108,326	18%
Total Gross Margin	$ 27,075,924	$ 25,913,612	$ 1,162,312	4%

Gas utility margins increased by 4% due to the combination of higher residential and commercial sales volumes and a non-gas rate increase. Although total delivered volumes were nearly unchanged from last year, the higher margin residential and commercial volumes increased by 6% due to the colder weather. A portion of the margin increase related to the higher volumes was mitigated due to the recognition of approximately $363,000 of WNA revenues in the prior year. In June 2009, the SCC approved the implementation of rates to provide for $1,198,000 in additional annual revenue. The increased rates have been in effect since November 1, 2008. 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 $576,000 of the increase in margin, while volumetric sales margins accounted for approximately $541,000 in additional margin including the WNA offset recognized in fiscal 2008.

Other margins increased by $108,326 due to increased levels of paving and consulting services.

The components of the gas utility margin and other margin increases are summarized below:

Net Utility Margin Increase

Customer Base Charge including rate increase	$ 576,238
Volumetric (rate increase and volume)	904,624
WNA	(363,376)
Carrying Cost	(23,460)
Other	(40,040)
Total	$ 1,053,986

Other Operating Expenses Operations expenses increased $458,025, or 5%, in fiscal 2009 compared with fiscal 2008 as a result of increases in employee benefit costs, contractor services and company labor combined with a lower level of capitalized overheads. Employee benefit expenses increased due to an $83,000 increase in pension costs attributable to lower than expected returns on a reduction in plan asset levels and the amortization of an actuarial loss in fiscal 2009 combined with a $95,000 increase in health insurance premiums. The Company expects pension costs to increase significantly in fiscal 2010 due to a higher expected actuarial loss while the increase in medical costs should be more moderate. Contractor services increased $54,000 due to timing related to the completion of leak surveys. Company labor expense increased by $179,000 primarily due to wage adjustments and labor allocations. A reduction in capital expenditures resulted in a $60,000 decline in capitalized overheads. The remaining difference resulted from a variety of other minor expense variances.

Maintenance expenses increased by $295,299, or 20%, due to timing of pipeline leak repairs on the Company s distribution system identified through leak surveys and the completion of several facilities maintenance projects.

General taxes increased $72,916, or 6%, in fiscal 2009 compared to fiscal 2008 due to higher payroll taxes and property taxes on a greater level of taxable property.

Depreciation expense decreased by $670,418, or 15%, due to the implementation of updated depreciation rates effective as of October 1, 2008. The new rates were the result of a depreciation study that is required to be conducted and filed with the SCC every five years.

The effect of using the new depreciation rates resulted in a reduction of approximately $888,000 in expense. The remaining difference was associated with a greater level of depreciation attributable 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 income position in fiscal 2008 to a net expense position in 2009 due to significantly lower interest income on cash investments and a greater level of charitable giving.

Interest Expense Total interest expense for fiscal 2009 decreased by $114,976, or 6%, from fiscal 2008, as a result of declines in the interest rates on the Company s line-of-credit and a lower interest rate on the new $5,000,000 note which replaced a higher interest rate debt that matured in fiscal 2008.

Income Taxes Income tax expense from continuing operations increased $405,567, or 16%, from fiscal 2008 corresponding to a 15% increase in pre-tax earnings. The effective tax rate for fiscal 2009 was 38.0% compared to 37.7% in fiscal 2008.

Net Income and Dividends Income from continuing operations for fiscal 2009 was $4,869,010 compared to $4,257,824 for fiscal 2008. Basic and diluted earnings per share from continuing operations were $2.19 and $2.18 in fiscal 2009, including $0.25 associated with the effect of the change in depreciation rates, compared to $1.94 and $1.93 in fiscal 2008. Dividends declared per share of common stock were $1.28 in fiscal 2009 and $1.25 in fiscal 2008.

Asset Management

Roanoke Gas uses a third party 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.

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 for 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 agreement, long-term debt and capital raised through the Company s Dividend Reinvestment and Stock Purchase Plan (DRIP).

Cash and cash equivalents increased by $6,546,924 in fiscal 2009 compared to a $532,881 decrease in fiscal 2008. The following table summarizes the categories of sources and uses of cash:

Cash Flow Summary	**2009**	**2008**
Continuing operations:		
Provided by operating activities	$ 22,705,812	$ 497,778
Used in investing activities	(5,224,954)	(3,166,506)
Provided by (used in) financing activities	(10,933,934)	2,061,120
Cash provided by discontinued operations		74,727
Increase (decrease) in cash and cash equivalents	$ 6,546,924	$ (532,881)

The seasonal nature of the natural gas business causes operating cash flows to 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 related cash flows. Generally, operating cash flows are positive during the second and third quarters as a combination of earnings, declining 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 2009, cash

provided by continuing operating activities increased by approximately $22,208,000, from $498,000 in fiscal 2008 to $22,706,000 in fiscal 2009. The significant increase in over-collection of gas costs combined with reductions in gas in storage, accounts receivable and accounts payable due to the declining commodity price of natural gas accounted for most of the increase in cash provided by operations. Conversely, fiscal 2008 experienced rising gas costs during the year. The circumstances that resulted in the generation of significant levels of cash from operating activities were unusual and are not indicative of historical or expected results. The Company anticipates cash provided by operating activities to be much less or even become a use of cash in fiscal 2010.

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 increased by approximately $2,058,000 due to the $3,941,000 in net proceeds received from the sale of the Bluefield Operations in fiscal 2008 partially offset by a reduced level of capital expenditures. Total capital expenditures from continuing operations were approximately $5,753,000 and $6,539,000 for the years ended September 30, 2009 and 2008, respectively. Capital expenditures for expanding natural gas service declined from last year due to reductions in new construction, which resulted from the continuing slowdown in real estate development and the current economic environment. Expenditures under the Company s pipeline renewal program also declined as 5.6 miles of natural gas distribution main were replaced in fiscal 2009 compared to 8.9 miles in fiscal 2008. The decline in pipeline renewal activity was partially attributed to a greater focus on pipeline maintenance and repairs. The Company plans to continue its focus on pipeline renewals in 2010 and expects such expenditures to continue at comparable or higher levels for the next several years. Operating cash flow provided by depreciation contributed approximately $3,815,000 in support of fiscal 2009 capital expenditures, or approximately 66% of the total investment, compared to approximately $4,527,000, or 69% of the total investment in fiscal 2008. The Company also relies on its line-of-credit

agreement, other operating cash flows and long-term debt financing to provide the balance of the underlying funding for its capital expenditures. With the implementation of lower depreciation rates, future capital expenditure funding will be more dependent on corporate borrowing activity.

Financing activities generally consist of long-term and short-term borrowings and repayments, issuance of stock and the payment of dividends. As discussed above, the Company uses its line-of-credit arrangement to fund seasonal working capital needs as well as provide temporary financing for capital projects. Cash flow from continuing financing activities changed by nearly $13,000,000, moving from more than $2,000,000 in cash generated to nearly $11,000,000 in cash used in fiscal 2009. The primary factor in the change corresponds to the net pay down in the Company s line-of-credit balance due to the cash generated from operating activities and the issuance of a new note. The Company entered into a $5,000,000 variable rate note in October 2008 and used the proceeds to refinance a portion of the line-of-credit balance that provided temporary funding for the retirement of a $5,000,000 first mortgage note that matured in July 2008.

On March 23, 2009 the Company renewed its line-of-credit agreement for Roanoke Gas. Although the Company was able to renew the line-of-credit, the credit markets at the time of renewal resulted in the renewal being on terms less favorable than the expiring agreement. The new agreement increased the variable interest rate to 30-day LIBOR plus 100 basis points and imposed an availability fee of 15 basis points applied to the difference between the face amount of the note and the average outstanding balance during the period. In response to the implementation of an availability fee, the bank agreed to adjust the available limits on a monthly basis to accommodate the Company s seasonal borrowing demands and minimize overall borrowing costs. Under the agreement, the Company s total available limits during its term range from $1,000,000 to $18,000,000. Furthermore, the bank also agreed to allow the Company to reduce the available borrowing limits during the term of the agreement in order to minimize the impact of the availability fee on the Company. Subsequent to September 30, 2009, the Company requested a reduction in the available limits under the line-of-credit agreement due to its current cash position. The Company s total available limits under the remaining term of the line-of-credit agreement as of September 30, 2009 and as amended subsequently are as follows:

Period Beginning	Available Limit at September 30, 2009	Revised Limit
September 30, 2009	$ 3,000,000	$ 3,000,000
October 24, 2009	18,000,000	7,000,000
November 25, 2009	15,000,000	7,000,000
January 23, 2010	8,000,000	8,000,000
February 25, 2010	5,000,000	5,000,000

The line-of-credit agreement will expire March 31, 2010, unless extended. The Company anticipates being able to extend or replace the line-of-credit upon expiration; however, there is no guarantee that the line-of-credit will be extended or replaced under the terms currently in place.

The Company s $15,000,000 variable rate note is currently scheduled to mature December 1, 2010. The note provides for an interest rate of LIBOR plus 69 basis points and has an interest rate swap that essentially converts the note into a fixed rate instrument at a rate of 5.74%. Due to the current economic climate and its effect on the credit markets, the Company has been unable to extend the note by more than one year without incurring a higher interest rate than is currently in place. The current credit market has increased the interest rate spreads on commercial debt instruments. The Company has had preliminary discussions with the issuing bank regarding extension of the note and anticipates being able to extend the note on a one year basis on terms comparable to the current note.

The remainder of the financing cash flows was associated with approximately $765,000 of proceeds related to stock issuances under the DRIP and Key Employee Stock Option Plan, $87,000 receipt on the note with ANGD, Inc. and approximately $2,800,000 in dividends paid.

At September 30, 2009, the Company s consolidated long-term capitalization was 62% equity and 38% debt, compared to 65% equity and 35% debt at September 30, 2008.

Regulatory Affairs

On November 1, 2008, Roanoke Gas Company placed into effect new base rates designed to produce $1,198,000 in additional annual revenues. The Company received a final order from the SCC on June 10, 2009 approving the full amount of the requested revenue.

The final order also included an agreement to modify the WNA mechanism, which mitigates the impact of temperature volatility on the Company s margin due to weather. The order approved a request to reduce the current weather band from approximately 6% of the 30-year average to a weather band of 3% of the 30-year average starting with the WNA period that began in April 2009. The implementation of this new weather band will further reduce the downside margin exposure that the Company has to warmer than normal weather. In addition, the new weather band will correspondingly limit the upside margin benefit from colder than normal weather to a 3% level.

The Company also filed with the SCC on July 1, 2009 the results of an updated depreciation study, which is required every 5 years. The new depreciation study, which is based on average remaining service life, extended the expected life of the Company s LNG plant, natural gas service lines and computer equipment resulting in a reduction in the overall composite weighted average depreciation rate from 4.12% to 3.31%, based on September 30, 2008 utility plant balances. The SCC approved the depreciation study filing and instructed the Company to implement the new rates effective October 1, 2008. As a result, the Company recorded the full effect of the change in depreciation rates for the fiscal year ended September 30, 2009 in the Company s fourth quarter results of operations.

The Company completed an evaluation of its revenue requirements and determined that a rate filing for increased non-gas rates was not warranted in the current year. Management will continue to monitor the Company s financial performance to determine when to make the next rate filing.

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 is material to the financial statements and 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

FASB ASC No. 980, *Regulated Operations.* 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 ceased 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 are adjusted quarterly through the purchased gas adjustment (PGA) mechanism with administrative 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 $1,173,561 and $1,475,406 as of September 30, 2009 and 2008.

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 (post- retirement plan) to eligible employees. The expenses and liabilities associated with these plans, as disclosed in Note 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 September reflected a targeted allocation of 60% equity and 40% fixed income for an assumed long-term rate of return of 7.25% on the pension plan and a targeted allocation of 50% equity and 50% fixed income for an assumed long-term rate of return of 5.18% (net of income taxes) for the postretirement plan. Based on the assumptions described above and in Note 7, pension expense is expected to increase from approximately $459,000 in fiscal 2009 to $759,000 in fiscal 2010 and postretirement expense is expected to rise from approximately $540,000 in fiscal 2009 to $606,000 in fiscal 2010. The Company expects to contribute approximately $800,000 to its pension plan and $600,000 to its postretirement plan in fiscal 2010. Funding levels are expected to remain at this level or higher over the next several years. However, funding requirements under the Pension Protection Act of 2006 could require the Company to increase its projected contribution levels in order to prevent any benefit restrictions.

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 Pension Cost	Impact on Projected Benefit Obligation
Discount rate	-0.25%	$ 118,000	$ 690,000
Rate of return on plan assets	-0.25%	28,000	N/A
Rate of increase in compensation	0.25%	44,000	238,000

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.

Actuarial Assumption	Change in Assumption	Impact on Postretirement Benefit Cost	Impact on Accumulated Postretirement Benefit Obligation
Discount rate	-0.25%	$ 24,000	$ 313,000
Rate of return on plan assets	-0.25%	16,000	N/A
Health care cost trend rate	0.25%	25,000	323,000

Derivatives The Company may hedge certain risks incurred in its operation through the use of derivative instruments. The Company applies the requirements of FASB ASC No. 815, *Derivatives and Hedging,* 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 hedging and derivatives 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, 2009, the Company has collar agreements outstanding for the purpose of hedging the price of natural gas during the winter period for 800,000 decatherms. In addition, the Company also has a commodity contract for the purchase of 1,057,000 decatherms of gas at a price of $6.36 per decatherm. Any cost incurred or benefit received from the derivative or other hedging arrangements would be expected to be recovered or refunded through the regulated natural gas 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 variable interest rates on its debt. The Company has two variable interest rate notes with banks that have corresponding swap agreements that essentially convert the debt to fixed rate debt. The valuation of the swap agreements are reflected in Note 1. The Company also has a variable rate line-of-credit with a bank with the interest rate based on the London Interbank Offered Rate (LIBOR). As of September 30, 2009, the Company had no outstanding balance under its line-of-credit.

Other Risks

The Company is exposed to risks other than commodity and interest rates. Such 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, Roanoke Gas has a means to recover increased costs through formal rate application filings, as well as the ability to 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 that delayed or prohibited the Company from placing rates into effect to timely recover costs and earn its authorized rate of return, the earnings of the Company could be negatively impacted. Furthermore, legislation at the state or federal level could result in increased costs and place additional burdens on the Company.

Environmental Legislation: The passage of environmental legislation that mandates reductions in carbon emissions or other similar restrictions could have a negative effect on the Company over the long-term as it relates to the Company s core operations. Natural gas is a clean and efficient energy source; however, the combustion of natural gas results in carbon related emissions. The extent to which carbon emissions would be restricted under any such legislation and the ability of technological improvements to minimize such emissions would be critical in determining any potential impact to the Company.

Energy Prices: Energy costs represent the single largest expense of the Company with the cost of natural gas representing approximately 76% and 80% for fiscal 2009 and 2008 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.

Pipeline Reliability: 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.

Customer Credit: 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, 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. Furthermore, adverse economic conditions and rising unemployment could also lead to an increase in delinquency of customer payments and higher bad debts. In addition, the SCC has specific notice requirements that the Company must first comply with before disconnecting natural gas service for customer nonpayment. The Company has mitigated some of the risk through deposit requirements. 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 that operated around a weather band of approximately 6% above and below the 30 year average for heating degree-days. This exposure to weather related risk was reduced in fiscal 2009 when the SCC approved changes to the WNA by reducing the weather band from 6% to 3%. Therefore, the Company should be at risk for no more than a 3% swing in heating degree-days above or below the 30 year 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

renewal of its line-of-credit arrangement in March; however, the new agreement was at less favorable terms than the expiring agreement. The new agreement increased the variable interest rate based on 30-day LIBOR and imposed an availability fee applied to the difference between the face amount of the note and the average outstanding balance during the period. The failure to obtain funding when needed, or obtain funding only on unfavorable terms, could have a significant negative impact to the Company.

Capitalization Ratios

Years Ended September 30,	2009	2008	2007	2006	2005
COMMON STOCK:					
Shares Issued	2,238,987	2,209,471	2,186,143	2,138,595	2,098,935
Continuing Operations:					
Basic Earnings Per Share	$ 2.19	$ 1.94	$ 1.74	$ 1.40	$ 1.40
Diluted Earnings Per Share	$ 2.18	$ 1.93	$ 1.73	$ 1.39	$ 1.39
Discontinued Operations:					
Basic Earnings Per Share	$ 0.00	$ (0.02)	$ 0.02	$ 0.26	$ 0.29
Diluted Earnings Per Share	$ 0.00	$ (0.02)	$ 0.02	$ 0.26	$ 0.29
Dividends Paid Per Share (Cash)	$ 1.28	$ 1.25	$ 1.22	$ 1.20	$ 1.18
Dividends Paid Out Ratio	58.4%	65.1%	69.3%	72.3%	69.8%
CAPITALIZATION RATIOS:					
Long-Term Debt, Including Current Maturities	38.5	34.5	39.8	40.9	42.3
Common Stock and Surplus	61.5	65.5	60.2	59.1	57.7
Total	100.0	100.0	100.0	100.0	100.0
Long-Term Debt, Including Current Maturities	$ 28,000,000	$ 23,000,000	$ 28,000,000	$ 28,000,000	$ 28,000,000
Common Stock and Surplus	44,799,871	43,723,058	42,365,233	40,494,868	38,157,357
Total Capitalization Plus Current Maturities	$ 72,799,871	$ 66,723,058	$ 70,365,233	$ 68,494,868	$ 66,157,357

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.

Fiscal Year Ended September 30,	Range of Bid Prices High	Low	Cash Dividends Declared
2009			
First Quarter	$ 30.07	$ 24.15	$ 0.320
Second Quarter	28.00	21.92	0.320
Third Quarter	27.38	22.95	0.320
Fourth Quarter	30.78	24.94	0.320
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

SUMMARY OF GAS SALES AND STATISTICS

Years Ended September 30,	2009	2008	2007	2006	2005
REVENUES:					
Residential Sales	$ 47,544,448	$ 52,927,761	$ 50,791,195	$ 52,274,204	$ 49,332,645
Commercial Sales	29,909,205	36,507,326	34,566,385	36,159,320	33,059,542
Interruptible Sales	635,301	1,509,193	1,379,870	3,054,240	3,029,697
Transportation Gas Sales	2,506,958	2,428,656	2,254,594	2,067,929	2,110,002
Backup Services	300	3,600	3,600	3,600	62,756
Late Payment Charges	56,718	55,410	55,438	70,191	55,109
Miscellaneous Gas Utility Revenue	133,298	174,647	124,579	116,924	102,918
Other	1,398,245	1,030,233	725,640	844,464	848,167
Total	$ 82,184,473	$ 94,636,826	$ 89,901,301	$ 94,590,872	$ 88,600,836
NET INCOME					
Continuing Operations	$ 4,869,010	$ 4,257,824	$ 3,765,669	$ 2,961,802	$ 2,916,798
Discontinued Operations		(36,690)	40,540	549,729	590,108
Net Income	$ 4,869,010	$ 4,221,134	$ 3,806,209	$ 3,511,531	$ 3,506,906
DTH DELIVERED:					
Residential	3,866,956	3,557,249	3,778,194	3,588,364	3,987,368
Commercial	2,830,782	2,785,701	2,886,403	2,793,988	2,859,471
Interruptible	75,061	128,875	138,176	278,535	321,860
Transportation Gas	2,487,670	2,779,429	2,735,456	2,853,500	3,202,923
Backup Service					5,531
Total	9,260,469	9,251,254	9,538,229	9,514,387	10,377,153
HEATING DEGREE DAYS	3,914	3,624	3,735	3,714	3,783
NUMBER OF CUSTOMERS:					
Natural Gas					
Residential	51,069	50,630	50,371	49,649	49,178
Commercial	5,018	5,026	5,017	4,948	4,939
Interruptible and Interruptible Transportation Service	32	33	32	32	36
Total	56,119	55,689	55,420	54,629	54,153
GAS ACCOUNT (DTH):					
Natural Gas Available	9,549,231	9,528,890	9,744,431	9,703,011	10,546,259
Natural Gas Deliveries	9,260,469	9,251,254	9,538,229	9,514,387	10,377,153
Storage - LNG	124,925	122,874	65,279	98,936	89,896
Company Use and Miscellaneous	39,697	45,180	28,862	36,321	47,568
System Loss	124,140	109,582	112,061	53,367	31,642
Total Gas Available	9,549,231	9,528,890	9,744,431	9,703,011	10,546,259
TOTAL ASSETS	$ 118,801,892	$ 118,127,714	$ 116,332,455	$ 114,662,572	$ 113,563,416
LONG-TERM OBLIGATIONS	$ 28,000,000	$ 23,000,000	$ 23,000,000	$ 28,000,000	$ 28,000,000

RGC Resources, Inc. and Subsidiaries

Consolidated Financial Statements

for the Years Ended September 30, 2009

and 2008, and Report of Independent

Registered Public Accounting Firm

RGC RESOURCES, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

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, 2009 and 2008, 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 audits 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 also 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, 2009 and 2008, 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

December 16, 2009

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2009 AND 2008

	2009	2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,422,360	$ 875,436
Short-term investments		500,000
Accounts receivable, less allowance for doubtful accounts of $50,687 in 2009 and $63,791 in 2008	3,562,837	5,086,790
Note receivable	87,000	87,000
Materials and supplies	587,815	553,604
Gas in storage	16,072,911	26,122,686
Prepaid income taxes	1,974,917	1,479,693
Deferred income taxes	3,424,628	2,187,795
Under-recovery of gas costs		1,013,087
Other	985,110	505,761
Total current assets	34,117,578	38,411,852
UTILITY PROPERTY:		
In service	118,009,532	113,533,184
Accumulated depreciation and amortization	(41,104,408)	(39,038,120)
In service, net	76,905,124	74,495,064
Construction work in progress	1,604,046	1,113,008
Utility plant, net	78,509,170	75,608,072
OTHER ASSETS:		
Note receivable	1,126,000	1,213,000
Regulatory assets	4,989,347	2,762,241
Other	59,797	132,549
Total other assets	6,175,144	4,107,790
TOTAL ASSETS	$ 118,801,892	$ 118,127,714

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2009 AND 2008

	2009	2008
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Borrowings under lines-of-credit	$	$ 13,960,000
Dividends payable	716,556	690,538
Accounts payable	4,449,735	8,215,319
Customer credit balances	4,204,556	4,237,043
Income taxes payable		3,206
Customer deposits	1,601,206	1,522,480
Accrued expenses	2,219,587	2,111,614
Over-recovery of gas costs	5,651,847	
Fair value of marked-to-market transactions	2,451,055	875,487
Total current liabilities	21,294,542	31,615,687
LONG-TERM DEBT	28,000,000	23,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	2,735,735	2,608,995
Regulatory cost of retirement obligations	7,401,024	6,843,338
Benefit plan liabilities	7,970,074	4,768,785
Deferred income taxes	6,534,621	5,471,667
Deferred investment tax credits	66,025	96,184
Total deferred credits and other liabilities	24,707,479	19,788,969
COMMITMENTS AND CONTINGENCIES (Notes 10 and 11)		
CAPITALIZATION:		
Stockholders Equity:		
Common Stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 2,238,987 and 2,209,471 shares in 2009 and 2008, respectively	11,194,935	11,047,355
Preferred stock, no par; authorized 5,000,000 shares; no shares issued and outstanding in 2009 and 2008		
Capital in excess of par value	16,607,897	15,990,961
Retained earnings	19,881,745	17,909,134
Accumulated other comprehensive loss	(2,884,706)	(1,224,392)
Total stockholders equity	44,799,871	43,723,058
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 118,801,892	$ 118,127,714

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

	2009	**2008**
OPERATING REVENUES:		
Gas utilities	$ 80,786,228	$ 93,606,593
Other	1,398,245	1,030,233
Total operating revenues	82,184,473	94,636,826
COST OF SALES:		
Gas utilities	54,408,778	68,283,129
Other	699,771	440,085
Total cost of sales	55,108,549	68,723,214
GROSS MARGIN	27,075,924	25,913,612
OTHER OPERATING EXPENSES:		
Operations	10,565,267	10,107,242
Maintenance	1,765,511	1,470,212
General taxes	1,240,209	1,167,293
Depreciation and amortization	3,660,421	4,330,839
Total other operating expenses	17,231,408	17,075,586
OPERATING INCOME	9,844,516	8,838,026
OTHER INCOME (EXPENSE), Net	(70,091)	34,622
INTEREST EXPENSE	1,918,106	2,033,082
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	7,856,319	6,839,566
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	2,987,309	2,581,742
INCOME FROM CONTINUING OPERATIONS	4,869,010	4,257,824
DISCONTINUED OPERATIONS:		
Loss from discontinued operations, net of income tax benefit of ($14,628)		(36,690)
NET INCOME	4,869,010	4,221,134
OTHER COMPREHENSIVE LOSS, NET OF TAX	(1,671,535)	(749,137)
COMPREHENSIVE INCOME	$ 3,197,475	$ 3,471,997

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

	2009	**2008**
BASIC EARNINGS PER COMMON SHARE:		
Income from continuing operations	$ 2.19	$ 1.94
Discontinued operations		(0.02)
Net income	$ 2.19	$ 1.92
DILUTED EARNINGS PER COMMON SHARE:		
Income from continuing operations	$ 2.18	$ 1.93
Discontinued operations		(0.02)
Net income	$ 2.18	$ 1.91
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:		
Basic	2,223,727	2,201,263
Diluted	2,231,040	2,211,226

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
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, net of tax				(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
Change in measurement date - benefit plans, net of tax			(44,931)	11,221	(33,710)
Net income			4,869,010		4,869,010
Losses on hedging activities, net of tax				(1,000,965)	(1,000,965)
Change in net loss and transition obligation of defined benefit plans, net of tax				(670,570)	(670,570)
Tax benefits from stock option exercise		16,407			16,407
Cash dividends declared ($1.28 per share)			(2,851,468)		(2,851,468)
Issuance of common stock (29,516 shares)	147,580	600,529			748,109
Balance - September 30, 2009	$ 11,194,935	$ 16,607,897	$ 19,881,745	$ (2,884,706)	$ 44,799,871

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

	2009	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income from continuing operations	$ 4,869,010	$ 4,257,824
Adjustments to reconcile net income to net cash provided by operations:		
Depreciation and amortization	3,815,009	4,526,670
Cost of removal of utility plant, net	(263,446)	(202,843)
Loss on disposal of property		7,304
Change in over/under-recovery of gas costs	6,627,084	(1,542,532)
Deferred taxes and investment tax credits	812,532	(730,442)
Other noncash items, net	39,111	28,329
Changes in assets and liabilities which provided (used) cash:		
Accounts receivable and customer deposits, net	1,602,679	(556,147)
Inventories and gas in storage	10,015,564	(7,003,735)
Other current assets	(781,945)	310,119
Accounts payable, customer credit balances and accrued expenses, net	(4,029,786)	1,403,231
Total adjustments	17,836,802	(3,760,046)
Net cash provided by continuing operating activities	22,705,812	497,778
Net cash used in discontinued operations		(277,913)
Net cash provided by operating activities	22,705,812	219,865
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for utility property	(5,752,780)	(6,539,369)
Proceeds from disposal of utility property	27,826	17,540
Proceeds from sale of Bluefield Operations		3,855,323
Proceeds from sale of short-term investments	500,000	
Purchase of short-term investments		(500,000)
Net cash used in continuing investing activities	(5,224,954)	(3,166,506)
Net cash used in discontinued investing activities		(12,360)
Net cash used in investing activities	(5,224,954)	(3,178,866)

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

	2009	**2008**
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	$ 5,000,000	$
Retirement of long-term debt		(5,000,000)
Proceeds on collection of note	87,000	
Net borrowings (repayments) under line-of-credit agreements	(13,960,000)	9,152,000
Proceeds from issuance of common stock	764,516	640,845
Cash dividends paid	(2,825,450)	(2,731,725)
Net cash provided by (used in) continuing financing activities	(10,933,934)	2,061,120
Net cash provided by discontinued financing activities		365,000
Net cash provided by (used in) financing activities	(10,933,934)	2,426,120
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	6,546,924	(532,881)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	875,436	1,408,317
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 7,422,360	$ 875,436
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION:		
Cash paid during the year for:		
Interest	$ 1,897,818	$ 2,188,420
Income taxes, net of refunds	2,629,308	3,094,944
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 in November 2007.		

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2009 AND 2008

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 of Virginia, Inc., operating as Application Resources. Roanoke Gas is a natural gas utility, which distributes and sells natural gas to approximately 56,100 residential, commercial and industrial customers within its service areas in Roanoke, Virginia and the surrounding localities. 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.

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

The Company follows accounting standards set by the Financial Accounting Standards Board (FASB) and the Securities and Exchange Commission (SEC). The FASB sets Generally Accepted Accounting Principles (GAAP) that ensure consistent reporting of financial condition, results of operations and cash flows. Effective for reporting periods ending on or after September 15, 2009, the FASB recognized the FASB Accounting Standards Codification, also referred to as the Codification or ASC, as the authoritative source of U.S. accounting and reporting standards for use in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. The Codification was a result of a project of FASB to organize and simplify all authoritative GAAP literature into one source. References to GAAP issued by FASB contained in the footnotes to these financial statements are to the Codification. References to prior FASB accounting standards, interpretations, and guidance have been replaced with references to the particular topics in the Codification.

Resources has only one reportable segment as defined under FASB ASC No. 280 *Segment Reporting.* All intercompany transactions have been eliminated in consolidation.

Rate Regulated Basis of Accounting The Company s regulated operations follow the accounting and reporting requirements of FASB ASC No. 980, *Regulated Operations.* 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 situation 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). In the event that the provisions of FASB ASC No. 980 no longer apply to any or all regulatory assets or liabilities, the Company would write off such amounts and include them in the consolidated statement of income and comprehensive income for the period in which FASB ASC No. 980 no longer applied.

Regulatory assets and liabilities included in the Company s consolidated balance sheets as of September 30, 2009 and 2008 are as follows:

	September 30 2009	2008
Regulatory Assets:		
Current Assets:		
Under-recovery of gas costs	$	$ 1,013,087
Other:		
Accrued pension and postretirement medical	442,062	187,134
Utility Property:		
In service:		
Other	11,945	11,945
Other Assets:		
Regulatory assets:		
Premium on early retirement of debt	187,324	217,701
Accrued pension and postretirement medical	4,802,023	2,544,540
Total regulatory assets	$ 5,443,354	$ 3,974,407
Regulatory Liabilities:		
Current Liabilities:		
Over-recovery of gas costs	$ 5,651,847	$
Deferred Credits and Other Liabilities:		
Asset retirement obligations	2,735,735	2,608,995
Regulatory cost of retirement obligations	7,401,024	6,843,338
Total regulatory liabilities	$ 15,788,606	$ 9,452,333

As of September 30, 2009, the Company had regulatory assets in the amount of $5,120,973 on which the Company did 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 under Asset Retirement Obligations below. 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 as determined by depreciation studies required to be performed on the regulated utility assets of Roanoke Gas Company every five years. The Company completed its most recent depreciation study in July 2009 and received notification from the SCC to implement these new rates retroactive to October 1, 2008. The composite weighted-average depreciation rate under the new depreciation study was 3.31% for the year ended September 30, 2009 compared to 4.12% of average depreciable property for the year ended September 30, 2008. The effect on depreciation expense is considered a change in accounting estimate and is recorded in the period in which the Company received approval from the SCC. The effect of this change in estimate was to reduce depreciation expense by $888,466, increase income from continuing operations and net income by $551,204 and increase earnings per share by $0.25 for the year ended September 30, 2009.

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 but rather the result of cost-based regulation and are accounted for under the provisions of FASB ASC No. 980. Therefore, such amounts are classified as a regulatory liability.

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 an impairment which would cause a material effect on results of operations or financial condition.

Asset Retirement Obligations FASB ASC No. 410, *Asset Retirement and Environmental Obligations,* requires entities to record the fair value of a liability for an asset retirement obligation when there exists a legal obligation for the retirement of the asset. 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. 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 FASB ASC No. 980. The costs of retirement considered in the development of the depreciation component include those costs associated with the legal liability. Therefore, 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.

The following is a summary of the asset retirement obligation:

	Years Ended September 30	
	2009	2008
Balance, beginning of year	$ 2,608,995	$ 2,499,345
Accretion	141,816	121,982
Additions	16,312	27,766
Retirements	(31,388)	(40,098)
Balance, end of year	$ 2,735,735	$ 2,608,995

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, 2009, the Company did not have any bank deposits in excess of the FDIC insurance limits of $250,000. 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	
	2009	2008
Balance, beginning of year	$ 63,791	$ 46,710
Additions charged to bad debt expense	202,892	197,272
Recoveries of accounts written off	196,982	199,210
Accounts written off	(412,978)	(379,401)
Balance, end of year	$ 50,687	$ 63,791

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. Therefore, an accrual is made to estimate revenues for natural gas delivered to customers but not 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, 2009 and 2008 were $1,173,561 and $1,475,406, 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 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 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 natural gas 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.

Excise and Sales Taxes Certain excise and sales taxes imposed by the state and local governments in the Company s service territory are collected by the Company from its customers. These taxes are accounted for on a net basis and therefore are not included as revenues in the Company s Consolidated Statements of Income and Comprehensive Income.

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	
	2009	**2008**
Weighted average common shares	2,223,727	2,201,263
Effect of dilutive securities:		
Options to purchase common stock	7,313	9,963
Diluted average common shares	2,231,040	2,211,226

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.

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 FASB ASC No. 815, *Derivatives and Hedging,* 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 hedging and derivatives policy allows management to enter into derivatives for the purpose of managing commodity and financial market risks of its business operations. The Company s hedging and derivatives 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 as the SCC allows for full recovery of prudent costs associated with natural gas purchases. At September 30, 2009, the Company has collar agreements outstanding for the winter period to hedge 800,000 decatherms of natural gas. As the current market value of natural gas falls between the floor and ceiling prices of the collar agreements, there is no fair value reflected in the financial statements at September 30, 2009. If the fair value of these instruments had fallen below the floor or risen above the ceiling price of the collar, the fair value would have been recorded in the balance sheet under the caption Fair value of marked-to-market transactions with the offsetting entry to either under-recovery of gas costs or over-recovery of gas costs. At September 30, 2008, the Company had collar agreements outstanding to hedge 370,000 decatherms of natural gas with a fair value liability of $37,850.

The Company also has two interest rate swaps associated with its variable rate notes. The first swap relates to the $15,000,000 note issued in November 2005. This swap essentially converts the floating rate note based upon LIBOR into fixed rate debt with a 5.74% effective interest rate. The second swap relates to the $5,000,000 variable rate note issued in October 2008. This swap converts the variable rate note based on LIBOR into a fixed rate debt with a 5.79% effective interest rate. Both swaps qualify as cash flow hedges with changes in fair value reported in other comprehensive income.

No derivative instruments were deemed to be ineffective for any period presented.

The table below reflects the fair values of the derivative instruments and their corresponding classification in the consolidated balance sheets under the current liabilities caption of Fair value of marked-to-market transactions as of September 30, 2009 and 2008, respectively:

Fair Value of Derivative Instruments

	September 30 2009	2008
Derivatives designated as hedging instruments:		
Interest rate swaps	$ 2,451,055	$ 837,637
Natural gas collar arrangement		37,850
Total derivatives designated as hedging instruments	$ 2,451,055	$ 875,487

Based on the interest rate environment as of September 30, 2009, approximately $900,000 of the fair value on the interest rate hedges will be reclassified from other comprehensive loss into interest expense on the income statement over the next 12 months. Changes in LIBOR rates during that period could significantly change the estimated amount to be reclassified to income as well as the fair value of the interest rate hedges.

Other Comprehensive Income (Loss) A summary of other comprehensive income (loss) and financial instrument activity, including the effect of adopting the change in measurement date provisions of FASB ASC No. 715, *Compensation Retirement Benefits,* is provided below:

	Year Ended September 30	
	2009	**2008**
Interest Rate SWAPs		
Unrealized losses	$ (2,369,923)	$ (994,914)
Income tax	899,623	377,669
Net unrealized losses	(1,470,300)	(617,245)
Transfer of realized losses to interest expense	756,505	243,302
Income tax	(287,170)	(92,357)
Net transfer of realized losses to interest expense	469,335	150,945
Defined Benefit Plans		
Unrecognized net loss arising during the period	(1,153,897)	(503,411)
Income tax	438,481	191,296
Net unrecognized loss arising during the period	(715,416)	(312,115)
Transfer of realized losses to income	25,252	
Income tax	(9,599)	
Net transfer of realized losses to income	15,653	
Amortization of transition obligation	47,093	47,223
Income tax	(17,900)	(17,945)
Net amortization of transition obligation	29,193	29,278
Net other comprehensive loss	$ (1,671,535)	$ (749,137)
Change in measurement date	11,221	
Accumulated comprehensive loss - beginning of period	(1,224,392)	(475,255)
Accumulated comprehensive loss - end of period	$ (2,884,706)	$ (1,224,392)

The components of accumulated comprehensive loss as of September 30, 2009 and 2008 include:

	September 30	
	2009	**2008**
Interest rate swaps	$ (1,520,635)	$ (519,670)
Pension plan	(954,797)	(372,501)
Postretirement benefit plan	(409,274)	(332,221)
Total accumulated comprehensive loss	$ (2,884,706)	$ (1,224,392)

Newly Adopted Accounting Standards On October 1, 2008, the Company adopted the change in measurement date provision of SFAS No. 158, *Employers Accounting for Defined Benefit Pension and other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132R* (FASB ASC No. 715). FASB ASC No. 715 requires an employer to measure the funded status of each plan as of the Company s fiscal year end. The Company previously used a June 30 measurement date for its benefit plans. The change in measurement date eliminated the three month lag in recognizing expense between the measurement date and the end of the Company s fiscal year. The Company recorded a reduction 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 has begun a three year amortization of the regulatory asset, consistent with the Company s latest rate filing and order.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (FASB ASC No. 820). FASB ASC No. 820 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value methods. No new fair value measurements are required. Instead, it provides for increased consistency and comparability in fair value measurements and for expanded disclosure surrounding the fair value measurements. Disclosures regarding nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, were delayed for one year. The Company adopted the fair value provisions of FASB ASC No. 820 effective October 1, 2008. The adoption had no material impact on the Company s financial position, results of operations or cash flows. The disclosures required by FASB ASC No. 820 are included in Note 12.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (FASB ASC No. 815). FASB ASC No. 815 enhanced the current disclosure framework 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, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flow. The adoption of the additional disclosure provisions of FASB ASC No. 815 had no material impact on the Company s financial position, results of operations or cash flows. The additional disclosures required by FASB No. 815 are included in Notes 1 and 12.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (FASB ASC No. 855). FASB ASC No. 855 establishes general standards of accounting for and disclosure of events that occur subsequent to the balance sheet date but before financial statements are issued. The statement defines two types of subsequent events (1) recognized subsequent events, which provide additional evidence about conditions that existed at the balance sheet date, and (2) non-recognized subsequent events, which provide evidence about conditions that did not exist at the balance sheet date, but arose before the financial statements were issued. Recognized subsequent events are required to be recognized in the financial statements, and non-recognized subsequent events are required to be disclosed. FASB ASC No. 855 requires entities to disclose the date through which subsequent events have been evaluated and the basis for the date. The adoption of FASB ASC No. 855 had no material impact on the Company s financial position, results of operations or cash flows. The disclosures required for subsequent events are included in Note 13.

Recently Issued Accounting Standards Pending Adoption In December 2008, the FASB issued FASB Staff Position No 132(R)-1, (FSP 132(R)-1), *Employers Disclosures about Postretirement Benefit Plan Assets* (FASB ASC No. 715). FASB s objective of these changes is to improve disclosures about plan assets in employers defined benefit pension or other post-retirement plans by providing users of financial statements with an understanding of: (a) How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (b) The major categories of plan assets; (c) The inputs and valuation techniques used to measure the fair value of plan assets; (d) The effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period; and (e) Significant concentrations of risk within plan assets. The new disclosure requirements under FASB ASC No. 715 are effective for fiscal years ending after December 15, 2009. Although the Company has not completed its evaluation, management does not anticipate these changes to have a material impact on its financial position, results of operations or cash flows.

Other accounting standards that have been issued or proposed by the FASB or other standard-setting bodies are not expected to have a material impact on the Company s financial position, results of operations and cash flows.

2. DISCONTINUED OPERATIONS

Effective October 31, 2007, Resources closed on the sale of the stock of Bluefield Gas Company 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 to Appalachian Natural Gas Company, a subsidiary of ANGD, LLC. The sale of both the stock and the assets was essentially at book value and included the receipt of a $1,300,000 note from ANGD to partially finance the transaction. 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 components of the discontinued operations are summarized below:

		Year Ended September 30 2008
Total Revenues	$	457,777
Pretax Operating Loss		(105,216)
Continuing Costs		53,898
Income Tax Benefit		14,628
Discontinued Operations	$	(36,690)

3. REGULATORY MATTERS

The SCC exercises regulatory authority over the natural gas operations of Roanoke Gas. Such regulation encompasses terms, conditions and rates to be charged to customers for natural gas service, safety standards, extensions of service, accounting and depreciation.

On November 1, 2008, Roanoke Gas placed into effect new base rates that were designed to produce $1,198,000 in additional annual revenues. The Company received a final order from the SCC on June 10, 2009 approving the additional annual revenue effective November 1, 2008.

Also included as part of the final order was an agreement to modify the Weather Normalization Adjustment (WNA) mechanism, which mitigates the impact of temperature volatility on the Company s margin due to weather. The order approved a request to reduce the current weather band from approximately 6% to 3% of the most recent 30-year average with the WNA period that began in April 2009. The implementation of this new weather band will further reduce the downside exposure that the Company has to warmer than normal weather. In addition, the new weather band will also limit the upside benefit from colder than normal weather to a 3% level.

The Company also filed with the SCC on July 1, 2009 the results of an updated depreciation study, which is required every 5 years. The depreciation study, which is based on average remaining service life, extended the expected life of the Company s LNG plant, natural gas service lines and computer equipment resulting in a reduction in the overall composite weighted average depreciation rate from 4.12% to 3.31%, based on September 30, 2008 utility plant balances. The SCC approved the depreciation study filing and instructed the Company to implement the new rates effective as of October 1, 2008. As a result, the Company recorded the full effect of the change in depreciation rates for the fiscal year ended September 30, 2009 in the Company s fourth quarter results of operations. The effect of the change in depreciation rates on the Company s Consolidated Statement of Income and Comprehensive Income is included in Note 1.

4. BORROWINGS UNDER LINE-OF-CREDIT

The Company has available an unsecured line-of-credit with a bank which will expire March 31, 2010. The Company anticipates being able to extend or replace this line-of-credit. The Company s available unsecured line-of-credit varies 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 this agreement for the remaining term are as follows:

Effective	Available Line-of-Credit
September 30, 2009	$ 3,000,000
October 24, 2009	18,000,000
November 25, 2009	15,000,000
January 23, 2010	8,000,000
February 25, 2010	5,000,000

Subsequent to year end, the Company requested a reduction in the available line-of-credit to $7,000,000 for the period October 24, 2009 through January 22, 2010. The Company requested the change due to its cash position and to minimize fees associated with the unused portion of the line-of-credit.

A summary of the line-of-credit follows:

	2009	2008
Line-of-credit at year-end	$ 3,000,000	$ 27,000,000
Outstanding balance at year-end		13,960,000
Highest month-end balance outstanding	16,145,000	13,960,000
Average daily balance	3,758,000	3,660,000
Average rate of interest during year	2.44%	4.25%
Average rate of interest at year-end	1.25%	4.43%

5. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30 2009	September 30 2008
Unsecured note payable, with variable interest rate based on 30-day LIBOR (0.25% at September 30, 2009) plus 69 basis point spread, with provision for retirement on December 1, 2010	$ 15,000,000	$ 15,000,000
Unsecured note payable, with variable interest rate based on three month LIBOR (0.29% at September 30, 2009) plus 125 basis point spread, with provision for retirement on December 1, 2015	5,000,000	
Unsecured senior note 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
Total long-term debt	28,000,000	23,000,000
Less current maturities		
Total long-term debt	$ 28,000,000	$ 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, 2009 and 2008. At September 30, 2009, approximately $10,882,000 of retained earnings was available for dividends.

The Company may request an extension of the maturity date of the $15,000,000 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% effective interest rate. The swap has a maturity date of December 1, 2015. The Company has had preliminary negotiations with the Bank regarding the Company s desire to annually extend the $15,000,000 note at terms comparable to the note currently in place until such time as both the note and the corresponding swap matures.

On October 31, 2008, the Company issued a $5,000,000 variable rate note at three-month LIBOR plus 125 basis points. This note refinanced a first mortgage note that matured in July 2008 and had since been funded through the Company s line-of-credit. Simultaneous with the execution of the variable rate note, the Company entered into an interest rate swap to convert the variable rate note into a fixed rate debt with a 5.79% effective interest rate. Both the variable rate note and the interest rate swap mature on December 1, 2015.

The aggregate annual maturities of long-term debt for the next five years ending after September 30, 2009 and thereafter are as follows:

Years Ended September 30	Maturities
2010	$
2011	15,000,000
2012	
2013	
2014	
Thereafter	13,000,000
Total	$ 28,000,000

6. INCOME TAXES

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

	Years Ended September 30	
	2009	2008
Current income taxes:		
Federal	$ 1,700,418	$ 2,385,856
State	430,460	508,082
Total current income taxes	2,130,878	2,893,938
Deferred income taxes:		
Federal	842,379	(192,741)
State	44,210	(89,288)
Total deferred income taxes	886,589	(282,029)
Amortization of investment tax credits	(30,158)	(30,167)
Total income tax expense	$ 2,987,309	$ 2,581,742

Income tax expense for the years ended September 30, 2009 and 2008 differed from amounts computed by applying the U.S. Federal income tax rate of 34% to earnings before income taxes due to the following:

	Years Ended September 30	
	2009	**2008**
Income before income taxes	$ 7,856,319	$ 6,839,566
Income tax expense computed at the federal statutory rate	$ 2,671,148	$ 2,325,452
State income taxes, net of federal income tax benefit	313,282	276,404
Amortization of investment tax credits	(30,158)	(30,167)
Other, net	33,037	10,053
Total income tax expense	$ 2,987,309	$ 2,581,742

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

	September 30	
	2009	**2008**
Deferred tax assets:		
Allowance for uncollectibles	$ 19,241	$ 24,215
Accrued pension and postretirement medical benefits	2,148,874	1,888,963
Accrued vacation	204,615	195,733
Over-recovery of gas costs	2,145,442	
Costs of gas held in storage	907,937	933,035
Accrued gas costs		676,389
Deferred compensation	491,107	417,224
Interest rate swap	930,420	317,967
Other	227,831	184,318
Total deferred tax assets	7,075,467	4,637,844
Deferred tax liabilities:		
Utility plant	8,907,926	7,551,517
Accrued gas costs	1,277,534	
Under-recovery of gas costs		370,199
Total deferred tax liabilities	10,185,460	7,921,716
Net deferred tax liability	$ 3,109,993	$ 3,283,872

FASB ASC No. 740, *Income Taxes,* 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. During the prior year, the Company had an unrecognized tax benefit of $23,276 associated with line pack gas. The Company filed for a change in method of accounting in its fiscal 2008 tax return and the tax is being paid over a four year period. The Company has evaluated its tax positions and has not identified any additional uncertain tax positions. The Company s policy is to classify interest associated with uncertain tax positions as interest expense in the financial statements. Penalties are classified under other income (expense).

The Company files a consolidated federal income tax return 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, 2006 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, supplemental retirement and life insurance benefits to retired employees who meet specific age and service requirements. Employees hired prior to January 1, 2000 are eligible to participate in the plan. Employees must have a minimum of ten years of service and retire after attaining the age of 55 in order to vest in the postretirement plan. Retiree contributions to the plan are based on the number of years of service to the Company as determined under the defined benefit plan.

FASB ASC No. 715, *Compensation Retirement Benefits* requires employers who sponsor defined benefit plans to recognize the funded status of defined benefit pension 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 applied the provisions of FASB ASC No. 980, *Regulated Operations* and established a regulatory asset for the portion of the obligation expected to be recovered in rates in future periods. The regulatory asset is adjusted for the amortization of the transition obligation and recognition of actuarial gains and losses. The portion of the obligation attributable to the unregulated operations of the holding company is recognized in comprehensive income.

On October 1, 2008, the Company adopted the change in measurement date provision of the FASB ASC No. 715. FASB ASC No. 715 requires an employer to measure the funded status of each plan as of the Company s fiscal year end. The Company previously used a June 30 measurement date for its benefit plans. The change in measurement date eliminated the three month lag in recognizing expense between the measurement date and the end of the Company s fiscal year. The Company recorded a reduction to retained earnings, net of tax, of $44,931 and a reduction in accumulated comprehensive loss of $11,221 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.

The following tables set forth the benefit obligation, fair value of plan assets, the funded status of the benefit plans, amounts recognized in the Company s financial statements and the assumptions used. The information presented for 2009 includes the 15 month period from July 1, 2008 through September 30, 2009 as a result of adopting the change in measurement date provisions.

	Pension Plan		Postretirement Plan	
	2009	**2008**	**2009**	**2008**
Accumulated benefit obligation	$ 12,431,936	$ 10,437,064	$ 9,569,792	$ 8,304,632
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 13,755,421	$ 12,538,300	$ 8,304,632	$ 8,427,326
Service cost	504,533	429,461	154,570	140,327
Interest cost	1,058,627	769,517	630,026	511,387
Actuarial (gain) loss	980,245	429,383	951,608	(339,674)
Benefit payments, net of retiree contributions	(556,407)	(411,240)	(471,044)	(434,734)
Benefit obligation at end of year	$ 15,742,419	$ 13,755,421	$ 9,569,792	$ 8,304,632
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 11,400,327	$ 10,984,155	$ 5,190,941	$ 5,202,179
Actual return on plan assets, net of taxes	(565,364)	27,412	143,684	(300,504)
Employer contributions	900,000	800,000	1,300,000	724,000
Benefit payments, net of retiree contributions	(556,407)	(411,240)	(471,044)	(434,734)
Fair value of plan assets at end of year	$ 11,178,556	$ 11,400,327	$ 6,163,581	$ 5,190,941
Reconciliation of funded status:				
Funded status	$ (4,563,863)	$ (2,355,094)	$ (3,406,211)	$ (3,113,691)
Contributions made between the measurement date and fiscal year-end				700,000
Net amount recognized in the balance sheet	$ (4,563,863)	$ (2,355,094)	$ (3,406,211)	$ (2,413,691)
Amounts recognized in the balance sheets consist of:				
Noncurrent liabilities	$ (4,563,863)	$ (2,355,094)	$ (3,406,211)	$ (2,413,691)
Amounts recognized in accumulated other comprehensive loss:				
Transition obligation, net of tax	$	$	$ 109,896	$ 146,393
Net actuarial loss, net of tax	954,797	372,501	299,378	185,828
Total amounts included in other comprehensive loss, net of tax	$ 954,797	$ 372,501	$ 409,274	$ 332,221
Amounts deferred to a regulatory asset:				
Transition obligation	$	$	$ 531,096	$ 708,345
Net actuarial loss	3,203,563	1,607,687	1,386,314	415,642
Amounts recognized as regulatory assets	$ 3,203,563	$ 1,607,687	$ 1,917,410	$ 1,123,987

The Company expects that approximately $150,000, before tax, of accumulated other comprehensive loss will be recognized as a portion of net periodic benefit costs in fiscal 2010 and approximately $442,000 of amounts deferred as regulatory assets will be amortized and recognized in net periodic benefit costs in fiscal 2010.

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 2009 and 2008.

	Pension Plan		Postretirement Plan	
	2009	**2008**	**2009**	**2008**
Assumptions related to benefit obligations:				
Discount rate	5.50%	6.25%	5.50%	6.25%
Expected rate of compensation increase	4.00%	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%	5.18%	5.22%
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.

Components of net periodic benefit cost are as follows:

	Pension Plan		Postretirement Plan	
	2009	**2008**	**2009**	**2008**
Service cost	$ 504,533	$ 429,461	$ 154,570	$ 140,327
Interest cost	1,058,627	769,517	630,026	511,387
Expected return on plan assets	(1,077,687)	(821,381)	(345,893)	(286,504)
Amortization of unrecognized transition obligation			236,115	188,892
Recognized loss	88,233			
Net periodic benefit cost	$ 573,706	$ 377,597	$ 674,818	$ 554,102

The components of net periodic benefit costs shown above for 2009 reflect the 15 month expense from July 1, 2008 through September 30, 2009. The tables below segregate the 15 month expense into the three-month period associated with the change in measurement date that was recorded in retained earnings and regulatory asset and the 12 month expense for the year ended September 30, 2009 reflected in benefit expense.

	Pension		
	Change in Measurement Date	**12 Months 9/30/2009**	**2009**
Service cost	$ 100,908	$ 403,625	$ 504,533
Interest cost	211,726	846,901	1,058,627
Expected return on plan assets	(215,538)	(862,149)	(1,077,687)
Amortization of unrecognized transition obligation			
Recognized loss	17,646	70,587	88,233
Net periodic benefit cost	$ 114,742	$ 458,964	$ 573,706

	Postretirement		
	Change in Measurement Date	**12 Months 9/30/2009**	**2009**
Service cost	$ 30,914	$ 123,656	$ 154,570
Interest cost	126,005	504,021	630,026
Expected return on plan assets	(69,178)	(276,715)	(345,893)
Amortization of unrecognized transition obligation	47,223	188,892	236,115
Recognized loss			
Net periodic benefit cost	$ 134,964	$ 539,854	$ 674,818

The adjustment for the change in measurement date is classified in the balance sheet as follows:

	Pension	**Postretirement**	**Total**
Regulatory asset	$ 75,690	$ 101,594	$ 177,284
Unregulated operations	39,052	33,370	72,422
Total	$ 114,742	$ 134,964	$ 249,706
Retained earnings	$ 24,228	$ 20,703	$ 44,931

The assumed health care cost trend rates used in measuring the accumulated benefit obligation for the postretirement medical plan as of September 30, 2009 and 2008 are presented below:

	2009	2008
Health care cost trend rate assumed for next year	10.00%	8.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	5.00%
Year that the rate reaches the ultimate trend rate	2016	2011

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

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 101,609	$ (82,420)
Effect on accumulated postretirement benefit obligation	1,290,478	(1,063,561)

The Company s target and actual asset allocation in the pension and postretirement benefit plans as of September 30, 2009 and June 30, 2008 were:

	Pension Plan			Postretirement Plan		
	Target	2009	2008	Target	2009	2008
Asset category:						
Equity securities	50%-70%	58%	56%	40%-60%	33%	49%
Debt securities	30%-50%	33%	30%	40%-60%	14%	45%
Cash	0%	9%	14%	0%	53%	6%

The primary objectives of the Company s investment policy are 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 investment manager has taken a temporary defensive position in the postretirement plan with a more conservative investment allocation.

The Company expects to contribute $800,000 to its pension plan and $600,000 to its postretirement benefit plan in fiscal 2010.

The following table reflects expected future benefit payments:

Fiscal year ending September 30	Pension Plan	Postretirement Plan
2010	$ 449,000	$ 476,000
2011	450,000	487,000
2012	470,000	511,000
2013	498,000	519,000
2014	501,000	535,000
2015-2019	3,309,000	2,937,000

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 $246,186 and $246,338 for 2009 and 2008, respectively.

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, 2009, the number of shares available for future grants under the KESOP was 2,000 shares.

FASB ASC No. 718, *Compensation-Stock Compensation*, requires that compensation expenses be recognized for the issuance of equity instruments to employees. However, all options granted under the KESOP were issued prior to this requirement and fell under the provisions 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 FASB ASC No. 718 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.

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, 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
Options exercised	(7,500)	$ 20.767	
Options expired			
Options outstanding, September 30, 2009	22,000	$ 18.955	$ 18.100-$19.360

The intrinsic value of the options exercised during fiscal 2009 and 2008 were $43,218 and $14,251, respectively.

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, 2009 and 2008. No options were granted in 2009 and 2008. The Company received $155,750 and $41,750 from the exercise of options in 2009 and 2008, respectively.

	Options Outstanding and Exercisable			
	Shares	Remaining Life (Years)	Exercise Price	Intrinsic Value
	6,500	1.2	$ 19.250	$ 50,180
	9,000	2.2	19.360	68,490
	6,500	3.2	18.100	57,655
Weighted average	22,000	2.2	$ 18.955	$ 176,325

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 16,696 and 16,715 shares in 2009 and 2008, respectively. As of September 30, 2009, the Company had 253,990 shares available for issuance.

Restricted Stock Plan

The Board of Directors of the Company implemented the Restricted Stock Plan for Outside Directors (Plan) 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.

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 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 directors received a total of 4,802 shares of Restricted Stock in fiscal 2009, representing $91,410 in compensation and $37,087 in dividends reinvested. The directors also received a total of 4,232 shares of Restricted Stock in fiscal 2008, representing $89,980 in compensation and $30,707 in dividends reinvested. As of September 30, 2009, the Company had 11,430 shares available for issuance.

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. Shares from the Stock Bonus Plan may also be issued to certain employees and management personnel in recognition of their performance and service. Under the Stock Bonus Plan, the Company issued 848 and 781 shares valued at $21,880 and $22,163, respectively, in 2009 and 2008. As of September 30, 2009 the Company had 22,151 shares available for issuance.

10. ENVIRONMENTAL MATTERS
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 in 2007, 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.

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, 2009. 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, 2009 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**	**Natural Gas Contracts (Decatherms)**
2010	$ 9,914,260	$ 6,722,520	2,225,059
2011	9,914,260		317,864
2012	9,914,260		
2013	9,280,119		
2014	7,544,149		
Thereafter	9,878,812		

The Company purchased approximately $42,520,000 and $71,838,000 of gas under the asset management contracts in fiscal year 2009 and 2008 respectively.

The Company has historically entered into derivative financial contracts for the purpose of hedging the price on natural gas. As of September 30, 2009, the Company has contracted to hedge, through fixed price arrangements and derivative collar arrangements, a set amount of decatherms of natural gas for each month in the winter period. The fixed price arrangement reflects a total of 1,057,000 decatherms at a price of $6.36 per decatherm. The collar arrangement reflects a total of 800,000 decatherms. All decatherm amounts have a ceiling price of $8.00 per decatherm and a floor price of $4.40 per decatherm. See *Derivative and Hedging Activities* in Note 1 for more information.

12. FAIR VALUE MEASUREMENTS

Effective October 1, 2008, the Company adopted FASB ASC No. 820, *Fair Value Measurements and Disclosures,* for financial assets and liabilities that are measured and reported on a fair value basis. FASB ASC No. 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. FASB ASC No. 820 also establishes a fair value hierarchy that prioritizes each input to the valuation method used to measure fair value into one of the following three broad levels:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices in Level 1 that are either for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability, or inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 Unobservable inputs for the asset or liability where there is little, if any, market activity for the asset or liability at the measurement date.

The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets (Level 1) and the lowest priority to unobservable inputs (Level 3).

The following table summarizes the Company s financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements by level within the fair value hierarchy as of September 30, 2009:

		Fair Value Measurements		
	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Interest rate swaps	$ 2,451,055	$	$ 2,451,055	$
Total	$ 2,451,055	$	$ 2,451,055	$

The following table summarizes the fair value of the Company s financial assets and liabilities that are not adjusted to fair value in the financial statements. The carrying value of cash and cash equivalents, accounts receivable, accounts payable, customer credit balances and customer deposits are a reasonable estimate of fair value due to the short-term nature of these financial instruments.

			Fair Value Measurements		
	Carrying Amount	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:					
Note receivable	$ 1,213,000	$ 1,173,749	$	$	$ 1,173,749
Liabilities:					
Long-term debt	28,000,000	29,382,055			29,382,055

The fair value of the note receivable is estimated by discounting future cash flows based on a range of rates for similar investments adjusted for management s expectation of credit and other risks. The fair value of long-term debt is estimated by discounting the future cash flows of the fixed rate debt at rates extrapolated based on current market conditions. The variable rate long-term debt has interest rate swaps that effectively convert such debt to fixed rate. The values of the swap agreements are included in the first table above.

13. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through December 16, 2009, the date the financial statements were issued, and there were no items not otherwise disclosed impacting the Company s consolidated financial statements which required additional disclosure.

* * * * * *

CORPORATE INFORMATION

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American Stock Transfer & Trust Company

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COMMON STOCK

RGC Resources common stock is listed on the NASDAQ/ National Market under the trading symbol RGCO.

DIRECT DEPOSIT OF DIVIDENDS AND SAFEKEEPING OF STOCK CERTIFICATES

Shareholders can have their cash dividends deposited automatically into checking, savings or money market accounts. The shareholder s financial institution must be a member of the Automated Clearing House. Also, RGC Resources offers safekeeping of stock certificates for shares enrolled in the dividend reinvestment plan. For more information about these shareholder services, please contact the Transfer Agent, American Stock Transfer & Trust Company.

10-K REPORT

A copy of RGC Resources, Inc. s latest annual report to the Securities & Exchange Commission on Form 10 -K will be provided without charge upon written request to:

Dale P. Lee

VICE PRESIDENT AND SECRETARY

RGC Resources, Inc.

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

Access all of RGC Resources Inc. s Securities and Exchange filings through the links provided on our website at www.rgcresources.com.

SHAREHOLDER INQUIRIES

Questions concerning shareholder accounts, stock transfer requirements, consolidation of accounts, lost stock certificates, safekeeping of stock certificates, replacement of lost dividend checks, payment of dividends, direct deposit of dividends, initial cash payments, optional cash payments and name or address changes should be directed to the Transfer Agent, American Stock Transfer & Trust Company. All other shareholder questions should be directed to:

RGC Resources, Inc.

Vice President and Secretary

P.O. Box 13007

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FINANCIAL INQUIRIES

All financial analysts and professional investment managers should direct their questions and requests for financial information to:

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Access up-to-date information on RGC Resources and its subsidiaries at www.rgcresources.com.