RGC RESOURCES INC
Form ARS
December 21, 2005

Exhibit 13

FINANCIAL HIGHLIGHTS

Year Ended September 30,	2005	2004	2003
Operating Revenue - Natural Gas	**$ 99,196,587**	$ 83,703,964	$ 75,321,337
Energy Marketing Revenue	**$ 21,571,120**	$ 18,810,525	$ 13,091,137
Other Revenue	**$ 880,080**	$ 621,005	$ 421,479
Net Income - Continuing Operations	**$ 3,387,933**	$ 2,059,767	$ 1,998,779
Net Income - Discontinued Operations	**$ 118,973**	$ 10,874,246	$ 1,529,610
Basic Earnings Per Share - Continuing Operations	**$ 1.63**	$ 1.02	$ 1.01
Basic Earnings Per Share - Discontinued Operations	**$ 0.06**	$ 5.36*	$ 0.77
Regular Dividend Per Share - Cash	**$ 1.18**	$ 1.17	$ 1.14
Number of Customers - Natural Gas	**58,946**	58,081	57,691
Total Natural Gas Deliveries - DTH	**11,452,388**	11,903,920	12,041,193
Total Additions to plant	**$ 7,427,304**	$ 7,925,948	$ 6,774,991

* Reflects $4.69 gain on sales of assets.

To Our Shareholders

I am pleased to report company earnings of $3.5 million or $1.68 per average diluted share outstanding for the fiscal year. I am also pleased to report that our Board of Directors has increased the annualized dividend rate to $1.20 per share effective February 1, 2006 for shareholders of record on January 13, 2006.

While earnings of $1.68 per share is not a record level for RGC Resources, it is a strong performance in our first full year of operation following the sale of our propane distribution divisions and declaration of a $4.50 per share special dividend to shareholders paid from gain on that sale. Our strategy to focus on natural gas distribution operations and to re-deploy capital from the propane operation into our natural gas distribution system has proven financially successful in spite of a warmer than normal heating season, rising interest rates, and rising natural gas prices.

Delivered natural gas volumes decreased approximately 0.5 million decatherms or 4% to 11.5 million decatherms on 3% fewer heating degree days than experienced in 2004. In fact, fiscal year 2005 was 10% warmer than the 30-year average which is used for designing regulated service rates for cost recovery and return on invested capital. Fortunately, beginning in 2003, the company put in place, with regulatory approval, a weather normalization factor in Virginia which allows an annual bill adjustment to recover lost revenue margins for adverse annual weather experiences more than approximately 6% warmer than the trailing 30-year average. Likewise, if weather were more than approximately 6% colder than the trailing 30-year average, the excess revenue margin would be credited back to customer bills.

As part of our emphasis on the natural gas distribution system in fiscal 2005, we focused our capital outlays on system upgrade and growth. We completed the replacement of 7.6 miles of bare steel and cast iron mains and over 500 bare steel service lines as part of our ongoing replacement of older portions of our distribution system. In addition, we installed 12 miles of new main and over 1,300 new services for system growth and customer additions. We also continued our leak reduction and measurement improvement initiative, reducing the unaccounted for volume of natural gas to less than one percent as part of a steady improvement in that operational metric.

Our strategy to focus on natural gas distribution operations

and to re-deploy capital from the propane operation into our

natural gas distribution system has proven financially

successful in spite of a warmer than normal heating season,

rising interest rates, and rising natural gas prices.

To facilitate the timely recovery of depreciation expense and higher carrying cost on the additional investment, we were active in rate cases in Virginia and West Virginia. We filed for a base rate increase for Bluefield Gas Company in West Virginia in January 2005 and settled the case for a $331,000 increase in non-gas rates which were placed into effect in December 2005. In Virginia, we filed for a base rate increase in September 2004 and obtained a final order in March 2005 resulting in a $857,000 base rate increase. In September 2005, we filed another base rate increase request in Virginia and placed a $2 million increase, subject to refund, into effect in October 2005. A hearing by the Virginia Commission is scheduled for March 2006.

While our base, or non-gas, rate increases are important to the company for the timely recovery of increased operating costs and a reasonable return on invested capital, they have a relatively minor impact on customers. A $2 million increase to base rates in Virginia results in less than a 2% impact on total revenue. The real concern for customers is the dramatically increased cost of the natural gas energy commodity. We filed and placed into effect significantly higher gas cost rates in both Virginia and West Virginia in the fall of 2005. Depending on weather, the average residential customer will likely see their cost to heat with natural gas this winter increase by 40% to 50%.

The nation s natural gas pricing problem has been developing for over a decade as environmental regulations have encouraged the use of natural gas for increased electricity generation, while other environmental policies and government prohibitions have closed off access to new domestic sources of natural gas. These policies, in conjunction with natural gas infrastructure damage from recent hurricanes, have resulted in a tripling of the well head cost of natural gas in less than three years. While promoting increased use of natural gas as an environmentally friendly means of generating the nation s growing demand for more electricity, Congress has simultaneously kept in place a moratorium on exploration and development of key supply areas by denying access to over 85% of the offshore east and west coasts, the west coast of Florida, and much of the western Rocky Mountains.

Successful Strategy

For the last five years, the nation s energy and utility industries have lobbied Congress for an energy bill that would allow development of significant new sources of natural gas. Finally in the summer of 2005, an energy bill was adopted by Congress and signed by President Bush. After years of effort, the result was unfortunately an energy bill that did little for conservation and nothing to allow for exploration and development in the prohibited offshore areas where large deposits of natural gas are believed to exist.

The energy bill does provide tax and federal royalty incentives that will encourage more domestic natural gas exploration and development. Unfortunately, the drilling will have to occur in the same areas that we have been utilizing for the last 35 years, relying on improved technology to get more energy from existing fields. The bill also encourages drilling deeper and further offshore in the Gulf of Mexico. These energy production incentives match quite detrimentally with a 30-year weather cycle bringing a return of stronger and larger hurricanes. Less than 30 days after President Bush signed the new energy bill, Hurricane Katrina practically shut down natural gas production in the Gulf. Before the damage assessments could be completed, Hurricane Rita accomplished a 90% shutdown of Gulf region natural gas and oil production. The well head price of natural gas shot from an already record high for the month of August of $7 a decatherm to $14 a decatherm in early October. In the fall of 2005, the United States had the highest priced natural gas in the world.

While the intense spike in prices from hurricane damage will lessen with facility replacements and continued exploration, there will remain a growing supply and demand squeeze keeping pressure on prices. We believe long-term solutions must include developing the natural gas reserves in the east and west U. S. offshore coastal areas, as well as the western Rockies and Alaska. The country needs geographic supply diversity to counter our excessive

We believe long-term solutions must

include developing the natural gas reserves in

the east and west U. S. offshore coastal areas,

as well as the western Rockies and Alaska.

reliance on the Gulf region. This natural gas supply improvement should be coupled with the U. S. also getting serious about energy efficiency, conservation, economically viable alternative sources of energy, and development of an increased capability for importation of liquified natural gas from foreign sources. In essence, Congress needs to create a comprehensive long-term national energy policy. We are continuing our efforts, along with the American Gas Association, to encourage Congress to take appropriate action. We encourage our share-holders and customers to express that same concern to Congress, as a reliable, reasonably priced energy market in the United States is critical to continued economic vitality and security.

Another aspect of the federal energy bill of 2005 was repeal of the Public Utility Holding Company Act (PUCHA) of 1935. The Act will cease to be in effect after February 2006 and could have significant

METHANE: Is the main component of natural gas, a mixture containing about 75% CH_4, 15% ethane (C_2H_6), and 5% other hydrocarbons, such as propane (C_3H_8) and butane (C_4H_{10}).

Superior Energy Source

WATER: Water molecules are formed during the combustion of methane as carbon-hydrogen bonds are broken and reformed into hydrogen-oxygen bonds (water), and carbon-oxygen molecules (carbon dioxide). It is this process that produces energy.

implications for the energy utility industry. For 70 years, the PUCHA legislation has kept in place restrictions on ownership and geographic operation of public utility companies that have discouraged industry consolidation and served as a disincentive to attract new investment. Some level of increased industry consolidation is likely to occur as removal of strict limitations on investments and ownership of utilities takes effect and expected new capital becomes available for needed infrastructure projects and acquisitions.

We also continue to focus time and resources on compliance with the Sarbanes-Oxley federal legislation, particularly Section 404, which has resulted in significantly increased accounting and auditing costs. We implemented an outsourced internal audit program in 2005 and continue to review, redesign and enhance our internal accounting, information systems, and financial reporting controls to comply with the new legislative and regulatory requirements. The deadline for full implementation of Sarbanes-Oxley Section 404 was recently postponed to 2007 for smaller public companies like RGC Resources. In an effort to mitigate increasing external audit costs, the Audit Committee of the Board of Directors solicited competitive proposals for audit services and engaged Brown Edwards and Company as the company s independent auditors for 2006.

Another Congressional issue likely to affect our industry is evolving federal tax policy. In 2003, the tax rate on dividends and long-term capital gains was lowered to 15%. The tax rate reduction will expire in 2008 unless it is extended or made permanent by Congress. We will work along with the American Gas Association to make the tax reduction permanent and encourage our shareholders to express their wishes to Congress.

It remains an interesting and exciting time to be in the natural gas distribution business. Natural gas is and will continue to be a vital and environmentally superior energy source. The cover of our annual report depicts a methane (natural gas) molecule. It is a very important molecule for RGC Resources, and it will continue to be a primary energy source in our lives and our national economy for many years to come. Our industry does have price and supply issues to work through and the United States Congress needs to take action to allow access to new areas for exploration and development of additional natural gas supply. We will continue to work toward that goal.

We thank you for your continuing interest in our ongoing operations and for your decision to be a shareholder of RGC Resources. We continue to offer our dividend reinvestment and stock purchase plan for shareholders that desire automatic reinvestment of their dividends or wish to make direct purchases of stock. Please contact us at 540-777-3853 if you would like more information on the program.

Sincerely,

John B. Williamson, III

Chairman, President and CEO

It remains an interesting and exciting time to be in the natural gas distribution business. Natural gas is and will continue to be a vital and environmentally superior energy source.

Selected Financial Data

Years Ended September 30,	2005	2004	2003	2002	2001
Operating Revenues	**$ 121,647,787**	$ 103,135,494	$ 88,833,953	$ 69,311,118	$ 102,397,478
Operating Margin	**25,152,002**	23,381,094	21,918,225	19,522,244	21,869,388
Operating Income	**7,513,431**	5,182,537	5,283,862	4,978,003	4,647,832
Net Income Continuing Operations	**3,387,933**	2,059,767	1,998,779	1,936,156	1,302,024
Net Income Discontinued Operations	**118,973**	10,874,246	1,529,610	550,739	1,004,591
Basic Earnings Per Share Continuing Operations	**$ 1.63**	$ 1.02	$ 1.01	$ 1.00	$ 0.68**
Basic Earnings Per Share Discontinued Operations	**0.06**	5.36*	0.77	0.28	0.53
Cash Dividends Declared Per Share	**$ 1.18**	$ 5.67	$ 1.14	$ 1.14	$ 1.12
Book Value Per Share	**18.18**	17.73	16.90	16.36	16.05
Average Shares Outstanding	**2,079,851**	2,027,908	1,983,970	1,939,511	1,898,697
Total Assets	**113,563,416**	114,972,556	104,364,733	96,978,115	97,324,955
Long-Term Debt (Less Current Portion)	**30,000,000**	26,000,000	30,219,987	30,377,358	22,507,485
Stockholders Equity	**38,157,357**	36,621,522	33,857,614	32,068,997	30,725,072
Shares Outstanding at Sept. 30	**2,098,935**	2,065,408	2,003,232	1,960,418	1,914,603

* *Reflects $4.69 gain on sale of assets.*

** *Reflects $.32 per share impairment loss.*

FORWARD-LOOKING STATEMENTS

From time to time, 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. 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 the following: (i) failure to earn on a consistent basis an adequate return on invested capital; (ii) increasing expenses and labor costs and labor availability; (iii) price competition from alternative fuels; (iv) volatility in the price and availability of natural gas; (v) uncertainty in the projected rate of growth of natural gas requirements 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 and/or colder weather; (ix) developments in electricity and natural gas deregulation and associated industry restructuring; (x) variations in winter heating degree-days from normal; (xi) changes in environmental requirements, pipeline operating requirements and cost of compliance; (xii) impact of potential increased governmental oversight and compliance costs due to the Sarbanes-Oxley law; (xiii) failure to obtain timely rate relief for increasing operating or gas costs from regulatory authorities; (xiv) ability to raise debt or equity capital; (xv) impact of uncertainties in the Middle East and related terrorism issues, and (xvi) new accounting standards issued by the Financial Accounting Standards Board, 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 or similar words or future or conditional verbs such as will, 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.

Management s Discussion & Analysis

GENERAL

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 59,000 residential, commercial and industrial customers in Roanoke, Virginia and Bluefield, Virginia and West Virginia and the surrounding areas through its Roanoke Gas Company and Bluefield Gas Company subsidiaries. Natural gas service is provided at rates and for the terms and conditions set forth by the State Corporation Commission (SCC) in Virginia and the Public Service Commission (PSC) in West Virginia. Roanoke Gas and Bluefield Gas currently hold the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia and West Virginia service areas. These franchises are effective through January 1, 2016 in Virginia and August 23, 2009 in West Virginia. While there are no assurances, the Company believes that it will be able to negotiate acceptable franchises when the current agreements expire. Certificates of public convenience and necessity in Virginia are exclusive and are intended to be of perpetual duration.

Resources also provides unregulated energy products through Diversified Energy Company, which operates as Highland Energy Company. Highland Energy brokers natural gas to several industrial and commercial transportation customers of Roanoke Gas and Bluefield Gas. Although the energy marketing operations do not fall under the jurisdiction of the SCC and PSC, they are subject to or affected by various federal and state regulations. Prices are determined by the Company and are subject to market demands and price competition. In addition to an energy marketing company, Diversified Energy Company operated an unregulated propane operation under the name of Highland Propane Company. In July 2004, Resources sold the propane operations. These operations as such have been classified as discontinued operations in the financial statements. Please see the Discontinued Operations section below for further discussion.

Resources also provides information system services to software providers in the utility industry through RGC Ventures, Inc. of Virginia, which operates as Application Resources.

Management views warm winter weather; energy conservation, fuel switching and bad debts due to high energy prices; and competition from alternative fuels each as factors that could have a significant impact on the Company s earnings. The risk of warm winter weather has been partially mitigated due to the inclusion of a weather normalization adjustment (WNA) factor as part of Roanoke Gas Company s rate structure. The WNA operates based on a weather occurrence band around the most recent 30-year temperature average. The weather band provides approximately a 6 percent range around normal weather, whereby if the number of heating-degree days fall within approximately 6 percent above or below the 30-year average, no adjustments are made. However, if the number of heating degree-days were more than 6 percent below the 30-year average, the Company would add a surcharge to firm customer bills (those customers not subject to service interruption) equal to the equivalent margin lost below the approximate 6 percent deficiency. Likewise, if the number of heating-degree days were more than 6 percent above the 30-year average, the Company would credit firm customer bills equal to the excess margin realized above the 6 percent heating degree-days. The measurement period in determining the weather band extends from April through March with any adjustment to be made to customer bills in late spring. The Company realized approximately $445,000 in additional revenues for the weather band period ended March 31, 2005 as the heating-degree days for the period April 2004 through March 2005 were approximately 12 percent less than the 30-year average.

In particular, management has concerns regarding the significant increase in the price of natural gas. The combination of the damage to natural gas production and transportation facilities attributable to Hurricanes Katrina and Rita and increasing demands for natural gas for electric generation have resulted in a dramatic rise in natural gas prices. The effect of the increase in gas prices began in late August; however, the full impact will not be realized until fiscal 2006. If natural gas prices remain at these unprecedentedly high levels, the Company may encounter a more than proportionate increase in bad debts and sales volume reductions attributable to conservation or customers converting to other energy or heating fuels.

For the fiscal year ended September 30, 2005, the Company experienced a decline in sales volumes due to warmer winter weather. The effect of the warmer weather on the results of operations was mitigated due to the application of the weather normalization adjustment, a non-gas rate increase placed into effect in October 2004 and an increased level of carrying cost revenues as explained below.

RESULTS OF OPERATIONS CONTINUING OPERATIONS

Fiscal Year 2005 Compared With Fiscal Year 2004

OPERATING REVENUES Total operating revenue increased $18,512,293, or 18%, for the year ended September 30, 2005 (fiscal 2005) compared to the year ended September 30, 2004 (fiscal 2004).

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Gas Utilities	**$ 99,196,587**	$ 83,703,964	$ 15,492,623	19%
Energy Marketing	**21,571,120**	18,810,525	2,760,595	15%
Other	**880,080**	621,005	259,075	42%
Total Operating Revenues	**$ 121,647,787**	$ 103,135,494	$ 18,512,293	18%

The increase in operating revenues resulted from significantly higher natural gas costs, the implementation of base rate increases and the services agreement associated with the sale of the assets of Highland Propane Company. The average per unit cost of natural gas increased by 27% for regulated operations and 23% for energy marketing operations over last year. Other revenues increased by $259,075 due to revenues generated under the services agreement with the Acquiror of the assets of Highland Propane Company to provide billing, facility and other services. As discussed below, the services agreement was terminated prior to the end of the fiscal year. Only nominal activity and revenues will occur subsequent to contract termination.

GROSS MARGIN - Total gross margin increased $1,770,908, or 8%, for fiscal 2005 compared to fiscal 2004.

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Gas Utilities	**$ 24,263,694**	$ 22,833,506	$ 1,430,188	6%
Energy Marketing	**391,181**	254,716	136,465	54%
Other	**497,127**	292,872	204,255	70%
Total Gross Margin	**$ 25,152,002**	$ 23,381,094	$ 1,770,908	8%

Regulated natural gas margins increased $1,430,188, or 6%, as total delivered volumes decreased by 4% due to warmer winter weather. Tariff sales, composed mainly of weather sensitive residential and commercial volumes, declined by 3%. This decline in tariff sales primarily resulted from a 3% decline in heating degree days (an industry measure by which the average daily temperature falls below 65 degrees Fahrenheit) from the same period last year. Furthermore, total heating degree days for fiscal 2005 were 10% below the 30-year normal. Transportation services, consisting of delivered volumes of natural gas purchased from other than the regulated utilities, and generally correlated more with economic conditions, decreased 6%, primarily related to an industrial customer converting a portion of its processes to utilize coal to reduce energy costs. Continued high prices could result in more customers seeking lower-cost alternative fuel sources depending upon the price of natural gas compared to other energy sources, the ability of customers to utilize other fuels and the effect on air-pollution limitations.

Although total natural gas deliveries declined by 4%, regulated natural gas margins increased due to Commission approved non-gas cost rate increases placed into effect on October 23, 2004 by Roanoke Gas Company, combined with the rate design which provides timely recovery of the financing costs (carrying costs) related to the higher dollar investments in natural gas inventories and the WNA revenues. Both Roanoke Gas Company and Bluefield Gas Company placed increased rates into effect during the first quarter. Roanoke Gas Company s rates were placed into effect subject to refund pending a final order from the Virginia SCC. Bluefield Gas Company s rates were placed into effect in accordance with a final rate order issued by the West Virginia PSC. As a result of the rate increases, the Company realized approximately $459,000 in additional customer base charges, which is a flat monthly fee billed to each natural gas customer. Carrying cost revenues increased by approximately $685,000 due to a much higher level of investment in storage gas inventory compared to prepaid gas service for the same period last year resulting from the combination of higher prices and warmer weather reducing the withdrawal rates from storage. The balance of the increase in regulated natural gas margin is attributable to the volumetric portion of the rate increase and $445,000 in WNA revenues both of which combined to more than offset the impact of lower volumes.

Management s Discussion & Analysis

Beginning in April 2003, the SCC approved a rate structure that would allow Roanoke Gas Company to recover financing costs related to the level of investment in gas inventory and prepaid gas service. Therefore, during times of rising gas costs, Roanoke Gas would be able to recognize a greater level of revenues to offset the higher financing costs; conversely, Roanoke Gas will pass along savings to customers if financing costs decrease due to lower inventory and prepaid gas balances resulting from reductions in gas costs. During the first quarter of fiscal 2005, Bluefield Gas Company implemented a similar rate structure as part of its new rates. The net effect of increased storage gas levels and the implementation of the carrying cost revenue component for Bluefield Gas resulted in the approximately $685,000 increase in revenues and margin. During periods of declining gas costs and storage gas levels, the Company would experience a reduction in revenues and margins as well.

Energy marketing margins increased $136,465, or 54%, from last year, even though total delivered volumes decreased by 221,958 DTH, or 8%. The increase in margin was attributable to the sale of a 100,000 decatherm natural gas strip for $143,000 profit. At the time of the sale, the 100,000 decatherm strip (a commitment to purchase volumes of natural gas in the future for a fixed price) was not needed to meet the needs of Highland Energy s customers; therefore, the Company was able to take advantage of market conditions and realize a gain on the transaction. The volume decline was mainly attributable to the same industrial customer that led to the decline in transportation volumes under the regulated natural gas operations.

Other margins increased by $204,255, or 70%, due to the services agreement with the Acquiror of the assets of Highland Propane Company to provide billing, facility and other services as discussed in Discontinued Operations. This agreement has been terminated.

The table below reflects volume activity and heating degree-days:

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Tariff Sales	**8,209,107**	8,466,916	(257,809)	-3%
Transportation Volumes	**3,243,281**	3,437,004	(193,723)	-6%
Total Delivered Volumes	**11,452,388**	11,903,920	(451,532)	-4%
Highland Energy (DTH)	**2,736,004**	2,957,962	(221,958)	-8%
Heating Degree Days (Unofficial)	**3,783**	3,917	(134)	-3%

OTHER OPERATING EXPENSES Operations expenses decreased $492,894, or 4%, in fiscal 2005 compared with fiscal 2004 primarily as a result of lower employee benefit costs and the absence of debt retirement costs. Employee benefit costs decreased by $383,188, as a result of reduced pension costs and post-retirement medical costs due to an increase in the actuarial discount rate assumption used for fiscal 2005 expense calculations and lower medical insurance claim activity in the first quarter. Post-retirement medical costs were also reduced by the actuarial impact of Medicare Part D, whereby the Company reduced its post-retirement medical liability due to the benefits to be provided under Medicare Part D beginning in 2006 for those plans that offer actuarially equivalent drug coverage to the Medicare Plan. Both pension and post-retirement medical expense are expected to increase next year due to a reduction in the discount rate used in the calculation of the benefit obligations and the implementation of a new mortality table incorporating longer life expectancies. The Company has been self-insured for medical insurance purposes for the past several years with stop/loss coverage in place for extremely high claims. The self-insurance program generated volatility in expense due to fluctuating claim levels. Beginning in January 2005, the Company switched to fully insured coverage to provide a more predictable expense trend. Operations expense also decreased by $125,547 associated with an early termination fee paid in fiscal 2004 for the retirement of a fixed rate note for Highland Propane. In addition, the net operations portion of bad debt expense increased $60,513, or 13%, over fiscal 2004 on higher gross revenues. Gross bad debt expense actually increased by $197,254 over last year; however, effective

November 1, 2004, in accordance with a rate order from the PSC, Bluefield Gas Company began charging the gas cost component of bad debt expense to gas cost. The result of this change allows the Company to recover the gas cost portion of bad debt expense directly through the PGA factor rather than through a formal non-gas cost rate filing. For the year ended September 30, 2005, Bluefield Gas Company charged $136,741 of bad debt expense to gas cost.

Maintenance expenses decreased by $240,640, or 14%, as the prior fiscal year included a substantial amount of maintenance on exposed distribution gas mains, primarily bridge crossings, consisting of painting and wrapping exposed mains to prevent corrosion, the disposal of certain old and obsolete inventory of maintenance materials no longer considered useful and additional facility, buildings and ground maintenance.

General taxes increased $35,572, or 2%, in fiscal 2005 compared to fiscal 2004 due to higher business and occupation (B&O) taxes, a revenue sensitive tax related to the West Virginia natural gas operations and increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $137,976, or 4% due to capital expenditures associated with system expansion for adding new natural gas customers and pipeline and facility renewal projects.

Other expenses, net, increased $40,797 primarily due to loss on retirement of a propane air facility. For both fiscal 2005 and 2004, the other expense, net was reduced by investment income associated with the proceeds from the sale of the propane operations. The Company has utilized these funds for debt reduction and the payment of the $4.50 per share special dividend on December 8, 2004.

INTEREST EXPENSE Total interest expense for fiscal 2005 increased $141,557, or 8%, from fiscal 2004, although total average debt outstanding during the year decreased by 1%.

Debt Summary:

Year Ended September 30,	2005	2004	Increase/ (Decrease)	Percentage
Average Daily Balance:				
Long-term Fixed Rate Debt	**$ 24,000,000**	$ 23,688,524	$ 311,476	1%
Long-term Variable Rate Debt	**2,000,000**	2,000,000		0%
Short-term Variable Rate Debt	**8,497,216**	9,224,905	(727,689)	-8%
Total Variable Rate Debt	**10,497,216**	11,224,905	(727,689)	-6%
Total Debt	**34,497,216**	34,913,429	(416,213)	-1%
Average Interest Rate:				
Long-term Fixed Rate Debt	**6.79%**	6.89%	-0.10%	-1%
Variable Rate Debt	**3.34%**	1.92%	1.42%	74%

The increase in interest expense is attributable rising interest rates on the Company s variable rate debt as a result of the Federal Reserve s actions. Total average debt outstanding during the year declined slightly from last year; however, the average interest rate on the variable rate portion of debt increased by 142 basis points representing an increase of 74% over last year. The above analysis does not include the $4,200,000 in Diversified Energy debt that was retired in July 2004 and the corresponding interest expense included in discontinued operations on the income statement.

INCOME TAXES Income tax expense from continuing operations increased $820,374, or 67% over last year as pre-tax earnings reflected a comparable increase. The effective tax rate for fiscal 2005 was 37.6% compared to 37.2% in fiscal 2004.

NET INCOME AND DIVIDENDS Income from continuing operations for fiscal 2005 was $3,387,933 as compared to fiscal 2004 income from continuing operations of $2,059,767. The improvement in income from continuing operations derived from the non-gas cost rate increase, increased carrying cost revenues and the implementation of a WNA, all of which more than offset the impact of warmer winter weather. In addition, reductions in both operating and maintenance costs contributed to improved earnings. Basic and diluted earnings per share from continuing operations were $1.63 and $1.62 in fiscal 2005 compared with $1.02 and $1.01 in fiscal 2004, respectively. Dividends per share of common stock were $1.18 in fiscal 2005 and $1.17 in fiscal 2004, excluding the special $4.50 dividend.

Fiscal Year 2004 Compared With Fiscal Year 2003

OPERATING REVENUES Total operating revenue increased $14,301,541, or 16%, for the year ended September 30, 2004 (fiscal 2004) compared to the year ended September 30, 2003 (fiscal 2003). The increase in revenues resulted from a combination of higher natural gas costs and increased sales volumes in the energy marketing operations. The average per unit cost of natural gas increased by 22% for regulated operations over last year.

Management s Discussion & Analysis

GROSS MARGIN - Total gross margin increased $1,462,869, or 7%, for fiscal 2004 compared to fiscal 2003.

Year Ended September 30,	2004	2003	Increase/ (Decrease)	Percentage
Gross Margin:				
Gas Utilities	$ 22,833,506	$ 21,425,681	$ 1,407,825	7%
Energy Marketing	254,716	285,042	(30,326)	-11%
Other	292,872	207,502	85,370	41%
Total Operating Margin	$ 23,381,094	$ 21,918,225	$ 1,462,869	7%

Regulated natural gas margins increased $1,407,825, or 7%, as total delivered volumes decreased by 1% due to significantly warmer winter weather. Tariff sales, composed mainly of weather sensitive residential and commercial volumes, declined by 8%. This decline in tariff sales primarily resulted from a 10% decline in heating degree days from the same period last year. Furthermore, total heating degree days for fiscal 2004 were 7% below the 30-year normal. Transportation services, consisting of delivered volumes of natural gas purchased from other than the regulated utilities, correlated more with economic conditions, increased 19%, reflecting continued improvement in the economy and industrial production.

Although the volume of natural gas tariff sales declined by 8%, regulated natural gas margins increased due to Commission approved non-gas cost rate increases placed into effect on October 16, 2003 by Roanoke Gas Company and December 1, 2003 by Bluefield Gas Company. The total annual non-gas cost rate increase associated with the approved rate increases amounted to approximately $1,650,000 based upon a normal weather year. As a result of these higher rates, customer base charges, in the form of a flat monthly fee billed to each natural gas customer, rose $642,295 and volumetric margin increased $765,530.

Energy marketing margins decreased $30,326, or 11%, from fiscal 2003, even though total delivered volumes increased by 656,876 DTH, or 29%. The increase in sales volume was attributable to a combination of improving economic conditions and sales to two additional customers of the marketing operations. The new customers accounted for approximately 37% of the increased volume. The decline in unit margin (margin per decatherm) is reflective of an average 13% increase in energy prices and competitive conditions.

Other margins increased by $85,370, or 41%, over the same period last year due to billings for the fuel line protection program, a new service program which contributed approximately $65,000 to other margins and net fees earned in connection with the services and facilities provided to the Acquiror of the Company s propane assets subsequent to its sale.

Year Ended September 30,	2004	2003	Increase/ (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Tariff Sales	8,466,916	9,162,397	(695,481)	-8%
Transportation Volumes	3,437,004	2,878,796	558,208	19%

Total Delivered Volume	11,903,920	12,041,193	(137,273)	-1%
Highland Energy (DTH)	2,957,962	2,301,086	656,876	29%
Heating Degree Days (Unofficial)	3,917	4,349	(432)	-10%

OTHER OPERATING EXPENSES Operations expenses increased $1,122,254, or 11%, in fiscal 2004 compared with fiscal 2003. The increased operations expenses related to higher employee compensation and benefit costs, corporate insurance, professional services and debt retirement costs partially offset by reduced bad debt expense and greater capitalization of overheads. Employee benefit costs increased $194,782 primarily due to higher pension costs related to a reduction in the actuarial discount rate assumption and amortization of actuarial losses related to the investment performance of plan assets over the past few years. Total labor expense increased $ 710,642 associated with an increase in the number of employees, a focus on operational projects during the year and increased pay-for-performance compensation. Corporate property and liability insurance expense increased $73,647 on higher premiums associated with liability and workers compensation coverage. Professional services increased $217,048 due to increases in external audit fees, completion of an SCC mandated depreciation study on Roanoke Gas Company s assets, consulting services related to Sarbanes-Oxley Section 404 compliance, and consulting services related to the Company s pipeline integrity management program. The Company also incurred a fee of $125,547 for early termination of the $1,700,000 fixed rate note for Highland Propane. However, the Company experienced a reduction in operations bad debt expense of $89,313 related to enhanced collection efforts.

Maintenance expenses increased by $189,046, or 12%, as the Company completed a substantial amount of work on sections of the natural gas distribution system that are not buried in the ground, primarily on bridges, consisting of painting and/or wrapping exposed pipe to prevent corrosion. The Company also wrote off certain old and obsolete maintenance materials inventory no longer considered useful and performed additional facility, buildings and ground maintenance.

General taxes increased $127,743, or 9%, in fiscal 2004 compared to fiscal 2003 due to higher business and occupation (B&O) taxes, a revenue sensitive tax related to the West Virginia natural gas operations which accounted for approximately half of the increase in general taxes. The remainder of the increase was associated with higher net payroll tax expense related to greater levels of operations and maintenance labor and increased property taxes associated with greater levels of taxable property.

Depreciation expense increased $125,151, or 3% due to capital expenditures associated with system expansion for adding new natural gas customers, significant pipeline and facility renewal projects, and software and computer hardware upgrades. The level of increase in depreciation expense was smaller than would otherwise be expected due to the implementation of new depreciation rates for Roanoke Gas Company effective January 1, 2004. A depreciation study was completed and the new rates were approved by the SCC. The new depreciation rates would result in approximately $100,000 less depreciation expense on an annual basis, based upon plant account balances on the effective date.

Other expenses, net, decreased $131,116, or 87%, primarily due to investment income earned on the investment of proceeds from the sale of the propane operations. The Company received approximately $28.5 million from the sale of propane assets and invested the proceeds in short-term investments after retiring debt and making income-tax estimates, pending the payment of the $4.50 per share special dividend payable on December 8, 2004.

INTEREST EXPENSE Total interest expense for fiscal 2004 decreased $81,233, or 4%, from fiscal 2003, although total average debt outstanding during the year increased 6%.

Debt Summary:

Year Ended September 30,	2004	2003	Increase/ (Decrease)	Percentage
Average Daily Balance:				
Long-term Fixed Rate Debt	$ 23,688,524	$ 24,702,191	$ (1,013,667)	-4%
Long-term Variable Rate Debt	2,000,000		2,000,000	100%
Short-term Variable Rate Debt	9,224,905	8,248,874	976,031	12%
Total Variable Rate Debt	11,224,905	8,248,874	2,976,031	36%
Total Debt	34,913,429	32,951,065	1,962,364	6%
Average Interest Rate:				
Long-term Fixed Rate Debt	6.89%	7.13%	-0.24%	-3%
Variable Rate Debt	1.92%	1.99%	-0.07%	-4%

The decrease in interest expense resulted from a combination of the new variable-rate $2,000,000 Bluefield Gas note that replaced a 7.28% fixed rate note, the payoff of $1,000,000 installment of Roanoke Gas debt issue with a 9.2% coupon rate and lower average rate on the Company s line of credit balances. The downward trend in short-term interest rates experienced by the Company on its line-of-credit accounts ended in June 2004 when short term interest rates began to move upward in response to market pressures and Federal Reserve actions. The above analysis does not include the $4,200,000 in Diversified Energy debt that was retired in July 2004 and the corresponding interest expense included in discontinued operations on the income statement.

INCOME TAXES Income tax expense from continuing operations increased $50,036, or 4%, from last year as both pre-tax earnings and the federal income tax rate increased as a result of the gain realized on the sale of assets. The total effective tax rate for fiscal 2004 was 37.2% compared to 36.9% in fiscal 2003.

Management s Discussion & Analysis

NET INCOME AND DIVIDENDS Income from continuing operations for fiscal 2004 was $2,059,767 as compared to fiscal 2003 income from continuing operations of $1,998,779. The improvement in income from continuing operations derived from the non-gas cost rate increase, which more than offset the impact of a significantly warmer winter and higher operations and maintenance expenses. Basic and diluted earnings per share from continuing operations were $1.02 and $1.01 in fiscal 2004 compared with $1.01 and $1.00 in fiscal 2003, respectively. Dividends per share of common stock, excluding the special $4.50 dividend declared to shareholders related to the gain on sale of assets, were $1.17 in fiscal 2004 and $1.14 in fiscal 2003.

DISCONTINUED OPERATIONS

On July 12, 2004, Resources sold the propane assets of its subsidiary, Diversified Energy Company, d/b/a Highland Propane Company (Diversified), for approximately $28,500,000 in cash to Inergy Propane, LLC (Acquiror). The sale of assets encompassed all propane plant assets (with the exception of a limited number of specific assets being retained by Diversified), the name Highland Propane, customer accounts receivable, propane gas inventory and inventory of propane related materials. The Company realized a gain of approximately $9,500,000 on the sale of assets, net of income taxes.

Concurrent with the sale of assets, the Company entered into an agreement with Acquiror by which the Company continued to provide the use of office, warehouse and storage space, and computer systems and office equipment and the utilization of Company personnel for billing, propane delivery and related services for the term of one year with an option for an additional year. The Acquiror notified the Company of its intent not to extend the remaining portions of the agreement and to allow the contract to expire in July 2005 with the exception of a one year lease agreement for access to the storage yard in Bluefield, West Virginia. For the year ended September 30, 2005, the Company realized approximately $451,000 in other revenues and $266,000 in other margin attributable to this agreement.

The asset purchase agreement did not include land and buildings owned by Diversified. Acquiror leased 10 parcels of real estate consisting of bulk storage facilities and office space from Diversified with an option to purchase such parcels. Prior to the end of June, the Acquiror executed the option to purchase the real estate and closed on all 10 parcels. The Company realized a net gain on the sale of real estate of approximately $153,000.

IMPACT OF COST INCREASES AND ENERGY PRICES

Energy costs represent the single largest expense of the Company with the cost of natural gas representing approximately 81% for fiscal 2005 and 77% for both fiscal 2004 and 2003 of the total operating expenses of the Company s natural gas utility operations.

Concerns about adequate storage levels for the impending winter along with two major hurricanes affecting the Gulf of Mexico (Gulf) production areas caused natural gas prices to increase significantly. The NYMEX (New York Mercantile Exchange) settlement for October 2005 exceeded $13.90 per decatherm representing a $8.18 increase over October 2004 s price.

Storage concerns have abated, because the market expectations are that supplies will be sufficient to meet the upcoming winter demand. The Energy Information Administration reports that storage levels at the end of September, while below last year s levels, are above the five-year average. The elevated natural gas prices and recent mild weather have resulted in decreased short-term demand and have allowed for storage injections to be maintained. Production in the Gulf is being restored with most production expected to be back on-line by January 2006.

The hurricanes also disrupted oil refining in the Gulf resulting in higher prices for alternative fuels like propane and heating oil, lessening the short-term incentives for fuel switching.

To mitigate the impact of price volatility, Roanoke Gas Company and Bluefield Gas Company use a variety of hedging mechanisms. Summer storage injections and financial instruments were utilized during the past winter period and provided the Company with lower energy costs than would have been incurred through spot market purchases alone. The Company s natural gas storage levels were near capacity at September 30, 2005 with nearly 3.2 million decatherms in storage at an average cost of $7.35, which is well below October s commodity price. Due to the uncertain direction of natural gas prices, the Company had not yet entered into new derivative financial instruments prior to year-end.

Natural gas costs are fully recoverable under the present regulatory Purchased Gas Adjustment (PGA) mechanisms, and increases and decreases in the cost of gas are passed through to the Company s customers.

Although rising energy prices are recoverable through the PGA mechanism for the regulated operations, high energy prices may have a negative impact on earnings through increases in bad debt expense and higher interest costs because the delay in recovering higher gas costs requires borrowing to temporarily fund receivables from customers. The Company s rate structure provides a level of protection against the impact that rising energy prices may have on bad debts and carrying costs on LNG storage and gas in storage by allowing for more timely recovery of these costs. However, the rate structure will not protect the Company from increases in the rate of bad debts or increases in interest rates.

The Company is also affected by increases in non-gas costs such as property and liability insurance, labor costs, employee benefits, supplies and services included in operations and maintenance expense and the replacement cost of plant and equipment. The rates charged to natural gas customers to cover these costs may only be increased through the regulatory process via a rate increase application. The result is generally a lag in the recovery costs as the rate-making process is generally based upon historical data. During periods of increasing non-gas costs, recovery may not occur until the implementation of rates developed based upon these increased costs. Even then, implementation of new rates to recover increased costs is subject to approval by the respective regulatory commissions in Virginia and West Virginia.

CAPITAL RESOURCES AND LIQUIDITY

Due to the capital intensive nature of Resources utility and energy businesses as well as the related weather sensitivity, Resources primary capital needs are the funding of its continuing construction program and the seasonal funding of its natural gas inventories and accounts receivable. The Company s construction program is primarily composed of a combination of replacing aging bare steel and cast iron pipe with new plastic or coated steel pipe and expansion of natural gas system to meet the demands of customer growth. Total capital expenditures of continuing operations for fiscal 2005 were approximately $7.4 million allocated as follows: $6.8 for Roanoke Gas Company and $0.6 million for Bluefield Gas Company. Depreciation cash flow provided approximately $4.3 million in support of capital expenditures, or approximately 58% of total investment. Historically, consolidated capital expenditures for continuing operations were $7.9 million in 2004 and $6.8 million in 2003. Fiscal 2004 and 2003 capital expenditures also included $1.0 million and $1.5 million, respectively, for discontinued operations. It is anticipated that future capital expenditures will be funded with the combination of operating cash flow, sale of Company equity securities and issuance of debt.

Short-term borrowing, in addition to providing capital project bridge financing, is used to finance seasonal levels of natural gas inventory and accounts receivables. From April through October, the Company purchases natural gas to build inventory for winter delivery when demand is much greater. Furthermore, a majority of the Company s sales and billings occur during the winter months resulting in a corresponding increase in accounts receivable. The following table provides a quarterly perspective of the seasonality of accounts receivable and natural gas inventory and the corresponding trend of rising gas costs. Amounts are in thousands.

Period Ended ***(in thousands)***	**Gas in Storage/ Prepaid Gas Service**	**Accounts Receivable**	**Total**
September 30, 2003	$ 16,162	$ 5,242	$ 21,404
December 31, 2003	12,498	17,142	29,640
March 31, 2004	1,071	14,274	15,345
June 30, 2004	9,059	6,481	15,540
September 30, 2004	17,662	5,978	23,640
December 31, 2004	17,136	18,938	36,074
March 31, 2005	7,800	17,437	25,237
June 30, 2005	17,037	7,746	24,783
September 30, 2005	23,465	7,442	30,907

On March 29, 2005, the Company and Wachovia Bank renewed the Company s line of credit agreements. The agreements maintain the same variable interest rates based upon 30-day LIBOR and continue a tiered borrowing level to accommodate the Company s seasonal borrowing demands. Due to the seasonality of the business, the Company s borrowing needs are at their lowest in Spring, increase during the Summer and Fall due to gas storage purchases and construction and reach their maximum levels in Winter. The tiered approach keeps the

Management s Discussion & Analysis

Company s borrowing costs to a minimum by improving the level of utilization on its line of credit agreements and providing increased credit availability as borrowing requirements increase. The available limits under the remaining term of the line of credit agreements are as follows:

Effective	Available Line of Credit
September 30, 2005	$ 28,000,000
November 16, 2005	29,000,000
February 16, 2006	25,000,000

At September 30, 2005, the Company had $11,662,000 outstanding under its available lines of credit prior to the reclassification of $4,000,000 to long-term debt, as described below. The average rates on debt outstanding under the lines of credit were 3.15% in 2005,1.79% in 2004 and 1.99% in 2003. The lines do not require compensating balances. These lines of credit will expire March 31, 2006, unless extended. The Company anticipates being able to extend the lines of credit or pursue other options.

Subsequent to September 30, 2005, Roanoke Gas Company and Bluefield Gas Company each entered into agreements with financial institutions to refinance maturing debt. Roanoke Gas entered into an unsecured 5-year note with provision for annual renewals in the amount of $15,000,000. The proceeds of this note were used to refinance the $8,000,000 unsecured note due November 30, 2005 and $4,000,000 in outstanding line of credit balance. The remainder of the proceeds were used to call the $3,000,000 collateralized term debenture due in 2016 including a call premium of $206,250. Bluefield Gas Company entered into an unsecured 31-month variable rate note in the amount of $2,000,000. The proceeds of this note were used to refinance the $2,000,000 unsecured note due November 2005. The Company entered into an interest rate swap agreement on the Roanoke Gas Company note for the purpose of fixing the interest rate over the total term of the note.

Short-term borrowings, together with internally generated funds, long-term debt and the sale of common stock through the Company s Dividend Reinvestment and Stock Purchase Plan (the Plan), have been adequate to cover construction costs, debt service and dividend payments to shareholders. The Company utilizes a cash management program, which provides for daily balancing of the Company s temporary investment and short-term borrowing needs. The program allows the Company to maximize returns on temporary investments and minimize the cost of short-term borrowings. The Company anticipates such benefits to continue to be realized in the future.

Stockholders equity increased for the period by approximately $1.5 million, reflecting an increase of $1.0 million in retained earnings, exclusive of accumulated comprehensive loss of $0.3 million, and proceeds of $0.8 million from new common stock purchases through the Plan and the Restricted Stock Plan For Outside Directors and the exercise of stock options to purchase 7,500 shares of stock during the year.

At September 30, 2005, the Company s consolidated long-term capitalization was 56% equity and 44% debt, compared to 58% equity and 42% debt at September 30, 2004 reflective of the refinancing of $4,000,000 of the line of credit balance.

REGULATORY AFFAIRS

In Virginia, Roanoke Gas Company settled the case that it filed with the SCC in September of 2004 with a Final Order dated April 28, 2005, approving an increase in rates of $856,859. In September 2005, Roanoke Gas Company filed another case requesting an increase in rates of $2,000,781 and placed the requested rates in effect for service rendered on and after October 23, 2005 subject to refund for any differences between the implemented rates and the rates finally approved by the SCC. The rate increase was based on the 10.1% rate of return that was found to be appropriate in the Company s last general rate case. A hearing on the application is scheduled for March 29, 2006.

In West Virginia, Bluefield Gas Company settled the case that it filed with the PSC in January of 2005 with a Final Order dated October 27, 2005, approving an increase in non gas rates of $331,000 for bills rendered on and after December 2, 2005.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

RGC Resources, Inc. s contractual obligations as of September 30, 2005 representing cash obligations that are considered to be firm commitments are as follows.

	Payment due within the year ended September 30,					
	2006	2007	2008	2009	2010	Thereafter
Lines-of-Credit[1]	$ 7,662,000	$	$	$	$	$
Long-term Debt[1]			7,000,000			23,000,000
Natural Gas Commitments	7,483,137	39,000				
Pipeline and Storage Capacity	11,007,513	10,895,013	10,737,513	10,737,513	10,737,513	50,650,568
Total Contractual Obligations	$ 26,152,650	$ 10,934,013	$ 17,737,513	$ 10,737,513	$ 10,737,513	$ 73,650,568

[1] *Excludes interest payments attributable to the debt*

Total available lines-of-credit are scheduled to expire on March 31, 2006, at which time the Company expects to renew the contracts. See Footnote 5 in the consolidated financial statements for additional information.

See Footnote 6 in the consolidated financial statements for more information on long-term debt.

The Company has fixed price commitments to purchase natural gas and related transportation services for the energy marketing operations in the amount of $7,522,137 over the next two years and pipeline and storage capacity fees in the amount of $104,765,633 under contracts expiring at various times through the year 2020. The Company expects to recover these costs through the PGA mechanism.

The Company has commitments to purchase natural gas at market price over the next three years in the amount of 2,373,302 decatherms, 2,369,535 decatherms and 338,505 decatherms associated with the provisions of the Company s asset management agreement.

CRITICAL ACCOUNTING POLICIES

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 estimates and judgments 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 could differ from the estimates, which would affect the related amounts reported in the Company s financial statements. Although estimates and judgments are applied in arriving at many of the reported amounts in the financial statements, the following items may involve a greater degree of judgment.

REVENUE RECOGNITION Regulated utility sales and transportation revenues are based upon rates approved by the SCC for Roanoke Gas Company and the PSC for Bluefield Gas Company. The non-gas cost component of rates may not be changed without a formal rate increase application and corresponding authorization by the appropriate regulatory commission; however, the gas cost component of rates may be adjusted periodically through the PGA mechanism with approval from the respective commission. Roanoke Gas Company also has a WNA, which is designed to partially offset the impact of weather that is either more than 6 percent warmer than normal or 6 percent colder than normal over a 12 month period. Without the WNA, the Company s operating revenues and gross margins would have been reduced by approximately $445,000. Under the Company s unregulated energy marketing operations, revenues are recognized when the natural gas is delivered based on the contracted or market price.

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, current and historical data.

BAD DEBT RESERVES The Company evaluates the collectibility of its accounts receivable balances based upon a variety of factors including loss history, level of natural gas prices, delinquent account balances and general economic climate.

RETIREMENT PLANS The Company offers a defined benefit pension plan (pension plan) and a postretirement medical and life insurance plan (postretirement plan) to eligible employees. The expenses and liabilities associated with these plans as disclosed in Note 8 to the consolidated financial statements are determined through actuarial means requiring the estimation of certain assumptions and factors.

Management s Discussion & Analysis

In regard to the pension plan, these factors include assumptions regarding discount rate, expected long-term rate of return on plan assets, compensation increases and life expectancies, among others. Similarly, the post-retirement medical plan also requires the estimation of many of the same factors as the pension plan in addition to assumptions regarding 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 to name a few. 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.

The discount rate assumption was determined based upon the rates of return on high quality fixed income investments corresponding with the Company s projected benefit obligation. Based upon market conditions as of the valuation date and related market trends, the discount rate declined to 5.25% from 6.25% in fiscal 2004 and 6.00% in fiscal 2003.

The expected long-term rate of return on pension and postretirement plan assets is based on the target asset allocations for each plan and the corresponding long-term returns associated with such allocations. The target allocation for the pension plan assets is 60% equity investments and 40% fixed income investments resulting in an expected long-term rate of return of 7.5%. The target allocation for postretirement plan assets is 55% equity and 45% fixed income resulting in an expected 7% long-term rate of return.

The medical trend rate is a critical component in determining the benefit obligation under the postretirement plan. Based on actual cost trend rates and projected future trends in health care costs, the trend rate assumption was 9% for fiscal 2005 down from 10% in fiscal 2004 and 2003, declining to 4.75% by the year 2010.

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

Actuarial Assumption	Change in Assumption	Impact on 2005 Pension Cost	Impact on Projected Benefit Obligation
Discount rate	-0.25%	$ 61,000	$ 597,000
Rate of return on plan assets	-0.25%	19,000	N/A
Rate of increase in compensation	0.25%	33,000	210,000

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 2005 Postretirement Benefit Cost	Impact on Accumulated Postretirement Benefit Obligation
Discount rate	-0.25%	$ 23,000	$ 329,000
Rate of return on plan assets	-0.25%	7,000	N/A

Health care cost trend rate	0.25%	22,000	311,000

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

REGULATORY ACCOUNTING The Company s regulated operations follow the accounting and reporting requirements of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71). The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for the 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 any portion of the current regulated operations ceased to meet the criteria for application of the provisions of SFAS No. 71, the Company would remove the corresponding regulatory assets or liabilities from the consolidated balance sheets and reflect them within the consolidated statement of income and comprehensive income for the period in which the discontinuance occurred.

ASSET MANAGEMENT

Effective November 1, 2004, Roanoke Gas Company and Bluefield Gas Company (the Companies) each entered into a new asset management agreement with a third party. Each contract is a three-year agreement with terms similar to the agreements that expired in October whereby the third party has assumed the management of the Companies firm transportation and storage agreements. The new contracts call for the Companies to retain ownership of their storage gas rather than having the asset manager own the gas as specified under the previous contract. As a result of the new contracts, the balance sheet at September 30, 2005 includes a line item called gas in storage that is composed of the underground storage gas previously owned by the asset manager. The gas in storage line item replaces the prepaid gas service under the prior contract, which represented the Companies rights to receive an equal amount of gas in the future as provided by those agreements.

ENVIRONMENTAL ISSUES

Both Roanoke Gas Company and Bluefield Gas Company, subsidiaries of RGC Resources, Inc., operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the early 1950 s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. The extent of contaminants at these sites, if any, is unknown at this time. An analysis at the Bluefield Gas Company site indicates some soil contamination. The Company, with concurrence of legal counsel, does not believe any events have occurred requiring regulatory reporting. Further, the Company has not received any notices of violation or liabilities associated with environmental regulations related to the MGP sites and is not aware of any off-site contamination or pollution as a result of prior operations. Therefore, the Company has no plans for subsurface remediation at the MGP sites. Should the Company eventually 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. A stipulated rate case agreement between the Company and the West Virginia Public Service Commission recognized the Company s right to defer MGP clean-up costs, should any be incurred, and to seek rate relief for such costs. If the Company eventually incurs costs associated with a required clean-up of either MGP site, the Company anticipates recording a regulatory asset for such clean-up costs to be recovered in future rates. Based on anticipated regulatory actions and current practices, management believes that any costs incurred related to this matter will not have a material effect on the Company s financial condition or results of operations.

MARKET RISK

The Company is exposed to market risks associated with interest rates and commodity prices. Interest rate risk is related to the Company s outstanding long-term and short-term debt. Commodity price risk is experienced by the Company s regulated natural gas operations and energy marketing business. The Company s risk management policy, as authorized by the Company s Board of Directors, allows management to enter into both physical and financial transactions for the purpose of managing commodity and interest rate risks 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 is exposed to market risk related to changes in interest rates associated with its borrowing activities. As of September 30, 2005, the Company had $11,662,000 outstanding under its lines of credit (including $4,000,000 reclassified to long-term debt) and $2,000,000 outstanding on an intermediate-term variable rate note. Based upon outstanding borrowings at September 30, 2005, a 100 basis point increase in market interest rates applicable to the Company s variable rate debt (excluding those for which the Company has entered into fixed rate swaps) would have resulted in an increase in annual interest expense of approximately $137,000. The Company also has an

$8,000,000 intermediate-term variable rate note that is currently being hedged by a fixed rate interest swap. The fair value of the interest rate swap at September 30, 2005 amounted to a $13,606 unrealized gain on marked to market transactions included on the Consolidated Balance Sheet.

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, 2005, the Company had not entered derivative instruments for the purpose of hedging the price of natural gas. If the Company had entered into such derivative instruments, any cost incurred or benefit received from the derivative or other hedging arrangements would be expected to be recoverable or refunded through the regulated natural gas purchased gas adjustment (PGA) mechanism. Both the SCC and PSC currently allow 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.

OTHER RISKS

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

CREDIT AND CUSTOMER Gas costs represent a major portion of the total customer bill. Gas cost projections are up significantly for this coming winter, and customer s natural gas bills will reflect the increase. The Company has worked diligently at minimizing bad debts and bad debt write offs. However, management anticipates that the increase in natural gas prices could result in an increase in delinquencies as customers face higher natural gas bills as well as other higher energy costs. In addition, the respective regulatory commissions in Virginia and West Virginia have specific notice requirements with which the Company must comply before disconnecting natural gas service for customer nonpayment. The Company has mitigated some of the risk through increased deposit requirements based upon higher energy prices as well as obtained credit insurance coverage on certain of the Company s larger volume industrial customers. Furthermore, the Company s 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.

TERRORISM - Since the attacks of September 11, 2001, the potential for new terrorist attacks remain a concern. The Company monitors the national alert level and has a security plan in place to address elevated warning levels. The Company is also using insurance as a means to mitigate potential financial impact of a terrorist attack.

STOCK MARKET PERFORMANCE - Although equity investments have largely recovered from the worst of the 2001 and 2002 stock market decline, the poor stock market performance over those years has affected the Company s performance by increasing certain benefit plan expenses. RGC Resources, Inc. offers both a defined benefit pension plan and postretirement medical benefits. The Company funds both of these plans. Prior poor returns on the investments of these plans continued to have a negative impact resulting in increased expense accruals over the last several years. The Company has increased its funding levels for the defined benefit pension plan and has maintained a consistent funding plan for post retirement medical benefits. This funding plan has mitigated the impact of the underfunded position of both plans; however, the reduction in the discount rate (from 6.25% to 5.25%) used to perform the plans valuations combined with the adoption of new mortality tables have resulted in significant increases in the corresponding benefit obligations for both plans as well as the pension and postretirement medical expense for fiscal 2006. The increase in pension expense will be approximately $335,000, while the increase in post retirement medical expense will be approximately $92,000. The Company is seeking recovery of these higher costs in rate case filings.

CORPORATE ACCOUNTING IRREGULARITIES - As a consequence of the high-profile irregularities and accounting scandals at a few well-publicized companies, additional regulation and oversight have been legislated by Congress through the Sarbanes-Oxley law to be enforced by the SEC. Although the SEC has delayed the full implementation of Sarbanes-Oxley Section 404 for smaller public companies until fiscal year ending September 2007, the Company has incurred costs to comply with the new requirements. The Company anticipates that it will incur additional costs in the upcoming year to complete its implementation.

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. In 2003, Roanoke Gas Company received approval from the SCC for the use of a weather normalization adjustment factor as discussed above. The Company should be at risk for no more than a 6 percent swing in heating degree-days above or below average.

Capitalization Statistics

	2005	2004	2003	2002	2001
COMMON STOCK:					
Shares Issued	**2,098,935**	2,065,408	2,003,232	1,960,418	1,914,603
Continuing Operations:					
Basic Earnings Per Share	**$ 1.63**	$ 1.02	$ 1.01	$ 1.00	$ 0.68**
Diluted Earnings Per Share	**$ 1.62**	$ 1.01	$ 1.00	$ 1.00	$ 0.68
Discontinued Operations:					
Basic Earnings Per Share	**$ 0.06**	$ 5.36*	$ 0.77	$ 0.28	$ 0.53
Diluted Earnings Per Share	**$ 0.06**	$ 5.32	$ 0.77	$ 0.28	$ 0.53
Dividends Paid Per Share (Cash)	**$ 1.18**	$ 5.67	$ 1.14	$ 1.14	$ 1.12
Dividends Paid Out Ratio	**69.8%**	88.9%	64.0%	89.1%	92.6%
CAPITALIZATION RATIOS:					
Long-Term Debt, Including Current Maturities	**44.0**	41.5	48.0	48.7	43.1
Common Stock And Surplus	**56.0**	58.5	52.0	51.3	56.9
Total	**100.0**	100.0	100.0	100.0	100.0
Long-Term Debt, Including Current Maturities	**$ 30,000,000**	$ 26,019,987	$ 31,252,359	$ 30,482,485	$ 23,310,522
Common Stock And Surplus	**38,157,357**	36,621,522	33,857,614	32,068,997	30,725,072
Total Capitalization Plus Current Maturities	**$ 68,157,357**	$ 62,641,509	$ 65,109,973	$ 62,551,482	$ 54,035,594

* *Reflects $4.69 gain on sale of assets.*

** *Reflects $.32 per share impairment loss.*

Summary of Gas Sales & Statistics

Years Ended September 30,	2005	2004	2003	2002	2001
REVENUES:					
Residential Sales	**$ 54,523,348**	$ 47,739,414	$ 42,749,256	$ 33,261,150	$ 50,432,183
Commercial Sales	**38,782,038**	31,899,455	28,371,913	21,723,467	32,486,778
Interruptible Sales	**3,506,787**	1,680,953	2,238,792	771,439	1,300,369
Transportation Gas Sales	**2,153,279**	2,158,411	1,712,960	1,686,141	1,609,974
Backup Services	**62,756**	51,452	89,590	64,287	77,514
Late Payment Charges	**59,990**	76,142	101,785	100,015	237,579
Miscellaneous Gas Utility Revenue	**108,389**	98,137	57,041	41,448	50,724
Energy Marketing	**21,575,049**	18,810,525	13,091,137	11,107,532	14,756,066
Other	**880,080**	621,005	421,479	555,639	1,446,291
Total	**$ 121,651,716**	$ 103,135,494	$ 88,833,953	$ 69,311,118	$ 102,397,478
NET INCOME					
Continuing Operations	**$ 3,387,933**	$ 2,059,767	$ 1,998,779	$ 1,936,156	$ 1,302,024
Discontinued Operations	**118,973**	10,874,246	1,529,610	550,739	1,004,591
Net Income	**$ 3,506,906**	$ 12,934,013	$ 3,528,389	$ 2,486,895	$ 2,306,615
DTH DELIVERED:					
Residential	**4,433,020**	4,785,309	5,120,975	4,230,055	5,121,119
Commercial	**3,398,050**	3,468,138	3,685,017	3,258,766	3,732,953
Interruptible	**372,506**	207,939	345,678	156,923	192,659
Transportation Gas	**3,243,281**	3,437,004	2,878,796	2,906,988	2,833,758
Backup Service	**5,531**	5,530	10,727	10,782	9,738
Total	**11,452,388**	11,903,920	12,041,193	10,563,514	11,890,227
HEATING DEGREE DAYS	**3,783**	3,917	4,349	3,502	4,342
NUMBER OF CUSTOMERS:					
Natural Gas					
Residential	**53,245**	52,413	52,006	51,557	51,198
Commercial	**5,655**	5,623	5,638	5,627	5,529
Interruptible and Interruptible Transportation Service	**46**	45	47	45	43
Total	**58,946**	58,081	57,691	57,229	56,770
GAS ACCOUNT (DTH):					
Natural Gas Available	**11,668,310**	12,250,411	12,392,866	10,992,271	12,516,840
Natural Gas Deliveries	**11,452,388**	11,903,920	12,041,193	10,563,514	11,890,227
Storage - LNG	**89,896**	117,378	102,907	112,692	70,704
Company Use And Miscellaneous	**47,875**	52,972	44,450	62,046	31,480
System Loss	**78,151**	176,141	204,316	254,019	524,429
Total Gas Available	**11,668,310**	12,250,411	12,392,866	10,992,271	12,516,840
TOTAL ASSETS	**$ 113,563,416**	$ 114,972,556	$ 104,364,733	$ 96,978,115	$ 97,324,955
LONG-TERM OBLIGATIONS	**$ 30,000,000**	$ 26,000,000	$ 30,219,987	$ 30,377,358	$ 22,507,485

Market Price & Dividend Price 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	Range of Bid Prices Low	Cash Dividends Declared
2005			
First Quarter	$ 26.750	$ 23.060	$ 0.295
Second Quarter	29.550	24.950	0.295
Third Quarter	28.700	24.500	0.295
Fourth Quarter	27.739	25.620	0.295
2004			
First Quarter	$ 23.560	$ 22.210	$ 0.285
Second Quarter	24.850	21.790	0.295
Third Quarter	25.250	23.020	0.295
Fourth Quarter	35.750	23.251	0.295
Special Dividend			4.500

Officers

JOHN B. WILLIAMSON, III

Chairman of the Board, President, and Chief Executive Officer (1) (2) (3) (4) (5)

J. DAVID ANDERSON

Assistant Secretary and Assistant Treasurer (1) (2) (3) (4) (5)

JOHN S. D ORAZIO

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

HOWARD T. LYON

Vice President, Treasurer and Controller (1) (2) (3) (4) (5)

DALE P. MOORE

Vice President and Secretary (1) (2) (3) (4) (5)

JANE N. O KEEFFE

Vice President, Human Resources (1)

C. JAMES SHOCKLEY, JR.

Vice President, Operations [5]

ROBERT L. WELLS, II

Vice President, Information Technology [1] [3] [4]

(1) RGC Resources, Inc.

(2) Roanoke Gas Company

(3) Diversified Energy Company

(4) RGC Ventures of Virginia, Inc.

(5) Bluefield Gas Company

Board of Directors

NANCY H. AGEE

Chief Operating Officer/Executive Vice President

Carilion Health System

Director: (1) (2)

ABNEY S. BOXLEY, III

President and Chief Executive Officer

Boxley Materials Company

Director: (1) (2)

FRANK T. ELLETT

President

Virginia Truck Center, Inc.

Director: (1) (2)

MARYELLEN F. GOODLATTE

Attorney and Principal

Glenn Feldmann Darby & Goodlatte

Director: (1) (2)

J. ALLEN LAYMAN

Private Investor

Director: [1] [2]

GEORGE W. LOGAN

Chairman of the Board

Valley Financial Corporation

Chairman of the Board

Alliance Logistics Center (Warsaw, Poland)

Principal

Pine Street partners, LLC

Faculty

University of Virginia Darden Graduate School of Business

Director: [1]

S. FRANK, SMITH

Manager - 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 Operating Officer

RGC Resources, Inc.

Director: [(1) (2) (3) (4) (5)]

Subsidiary Boards of Directors:

JOHN S. D ORAZIO

Vice President and Chief Operating Officer

Roanoke Gas Company

Director: [(3) (4) (5)]

HOWARD T. LYON

Vice President, Treasurer and Controller

RGC Resources, Inc.

Director: [(3) (4) (5)]

DALE P. MOORE

Vice President and Secretary

RGC Resources, Inc.

Director: [(3) (4) (5)]

C. JAMES SHOCKLEY

Vice President, Operations

Diversified Energy Company

Director: [5]

ROBERT L. WELLS, II

Vice President, Information Technology

RGC Resources, Inc. Director: [3] [4]

[1] - RGC Resources, Inc.

[2] - Roanoke Gas Company

[3] - Diversified Energy Company

[4] - RGC Ventures of Virginia, Inc.

[5] - Bluefield Gas Company

RGC Resources, Inc. and Subsidiaries

Consolidated Financial Statements for the Years Ended September 30, 2005, 2004, and 2003, and Report of Independent Registered Public Accounting Firm

RGC RESOURCES, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

Deloitte & Touche LLP
1100 Carillon Building
227 West Trade Street
Charlotte, NC 28202
USA

Tel: + 1 704 887 1500
Fax: + 1 704 887 1570

www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RGC Resources, Inc.

We have audited the accompanying consolidated balance sheets of RGC Resources, Inc. and subsidiaries (the Company) as of September 30, 2005 and 2004, and the related consolidated statements of income and comprehensive income, stockholders equity and cash flows for each of the three years in the period ended September 30, 2005. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, on July 12, 2004, the Company sold substantially all of the assets of its subsidiary, Diversified Energy Company, d/b/a Highland Propane Company (Highland Propane), and on June 24, 2005 sold all remaining assets of Highland Propane.

December 15, 2005

Member of

Deloitte Touche Tohmatsu

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2005 AND 2004

	2005	2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,349,518	$ 9,461,217
Short-term investments		4,991,460
Accounts receivable, less allowance for doubtful accounts of $284,008 in 2005 and $38,525 in 2004	7,441,761	5,978,065
Materials and supplies	701,100	731,225
Gas in storage	23,464,537	1,739,024
Prepaid gas service		15,923,177
Prepaid income taxes	883,617	2,278,361
Deferred income taxes	2,533,770	1,818,280
Under-recovery of gas costs	2,248,410	580,166
Fair value of marked-to-market transactions	13,606	
Other	412,236	306,966
Total current assets	39,048,555	43,807,941
UTILITY PROPERTY:		
In service	107,663,713	102,086,697
Accumulated depreciation and amortization	(35,341,798)	(34,493,087)
In service net	72,321,915	67,593,610
Construction work in progress	1,774,804	2,405,107
Utility plant net	74,096,719	69,998,717
NONUTILITY PROPERTY:		
Nonutility property	22,762	794,013
Accumulated depreciation and amortization	(17,116)	(184,624)
Nonutility property net	5,646	609,389
Other assets	412,496	556,509
TOTAL ASSETS	$ 113,563,416	$ 114,972,556

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2005 AND 2004

	2005	2004
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$	$ 19,987
Borrowings under lines of credit	7,662,000	12,742,000
Dividends payable	619,532	9,903,993
Accounts payable	19,131,418	10,740,943
Customer deposits	991,864	712,892
Accrued expenses	4,305,766	4,356,680
Refunds from suppliers due customers	4,954	22,292
Over-recovery of gas costs		2,174,313
Fair value of marked-to-market transactions		73,356
Total current liabilities	32,715,534	40,746,456
LONG-TERM DEBT, EXCLUDING CURRENT MATURITIES	30,000,000	26,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	6,967,622	6,197,549
Deferred income taxes	5,524,841	5,174,829
Deferred investment tax credits	198,062	232,200
Total deferred credits and other liabilities	12,690,525	11,604,578
COMMITMENTS AND CONTINGENCIES (Notes 11 and 12)		
CAPITALIZATION:		
Stockholders equity:		
Common stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 2,098,935 and 2,065,408 shares in 2005 and 2004, respectively	$ 10,494,675	$ 10,327,040
Preferred stock, no par; authorized 5,000,000 shares; no shares issued or outstanding in 2005 and 2004		
Capital in excess of par value	13,720,348	13,064,566
Retained earnings	14,322,805	13,275,426
Accumulated other comprehensive loss	(380,471)	(45,510)
Total stockholders equity	38,157,357	36,621,522
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 113,563,416	$ 114,972,556

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2005, 2004, AND 2003

	2005	2004	2003
OPERATING REVENUES:			
Gas utilities	$ 99,196,587	$ 83,703,964	$ 75,321,337
Energy marketing	21,571,120	18,810,525	13,091,137
Other	880,080	621,005	421,479
Total operating revenues	121,647,787	103,135,494	88,833,953
COST OF SALES:			
Gas utilities	74,932,893	60,870,458	53,895,656
Energy marketing	21,179,939	18,555,809	12,806,095
Other	382,953	328,133	213,977
Total cost of sales	96,495,785	79,754,400	66,915,728
GROSS MARGIN	25,152,002	23,381,094	21,918,225
OTHER OPERATING EXPENSES:			
Operations	10,577,539	11,070,433	9,948,179
Maintenance	1,501,213	1,741,853	1,552,807
General taxes	1,530,702	1,495,130	1,367,387
Depreciation and amortization	4,029,117	3,891,141	3,765,990
Total other operating expenses	17,638,571	18,198,557	16,634,363
OPERATING INCOME	7,513,431	5,182,537	5,283,862
OTHER EXPENSES Net	60,418	19,621	150,737
INTEREST EXPENSE	2,025,293	1,883,736	1,964,969
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	5,427,720	3,279,180	3,168,156
INCOME TAX EXPENSE FROM CONTINUING OPERATIONS	2,039,787	1,219,413	1,169,377
INCOME FROM CONTINUING OPERATIONS	3,387,933	2,059,767	1,998,779
DISCONTINUED OPERATIONS:			
Income from discontinued operations net of income taxes of $73,540; $7,223,230 and $970,549 in 2005, 2004, and 2003, respectively	118,973	10,874,246	1,529,610
NET INCOME	3,506,906	12,934,013	3,528,389
OTHER COMPREHENSIVE INCOME (LOSS) NET OF TAX	(334,961)	109,040	(288,793)
COMPREHENSIVE INCOME	$ 3,171,945	$ 13,043,053	$ 3,239,596

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2005, 2004, AND 2003

	2005	2004	2003
BASIC EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.63	$ 1.02	$ 1.01
Discontinued operations	0.06	5.36	0.77
Net income	1.69	6.38	1.78
DILUTED EARNINGS PER COMMON SHARE:			
Income from continuing operations	$ 1.62	$ 1.01	$ 1.00
Discontinued operations	0.06	5.32	0.77
Net income	$ 1.68	$ 6.33	$ 1.77
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	2,079,851	2,027,908	1,983,970
Diluted	2,093,115	2,042,312	1,989,460

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2005, 2004 AND 2003

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
BALANCE September 30, 2002	$ 9,802,090	$ 11,374,173	$ 10,758,491	$ 134,243	$ 32,068,997
Net income			3,528,389		3,528,389
Losses on hedging activities net of tax				(288,793)	(288,793)
Cash dividends declared ($1.14 per share)			(2,267,960)		(2,267,960)
Issuance of common stock (42,814 shares)	214,070	602,911			816,981
BALANCE September 30, 2003	10,016,160	11,977,084	12,018,920	(154,550)	33,857,614
Net income			12,934,013		12,934,013
Gains on hedging activities net of tax				109,040	109,040
Cash dividends declared ($5.67 per share)			(11,677,507)		(11,677,507)
Issuance of common stock (62,176 shares)	310,880	1,087,482			1,398,362
BALANCE September 30, 2004	10,327,040	13,064,566	13,275,426	(45,510)	36,621,522
Net income			3,506,906		3,506,906
Gain on hedging activities net of tax				53,951	53,951
Minimum pension liability net of tax				(388,912)	(388,912)
Cash dividends declared ($1.18 per share)			(2,459,527)		(2,459,527)
Issuance of common stock (33,527 shares)	167,635	655,782			823,417
BALANCE September 30, 2005	$ 10,494,675	$ 13,720,348	$ 14,322,805	$ (380,471)	$ 38,157,357

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2005, 2004 AND 2003

	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income from continuing operations	$ 3,387,933	$ 2,059,767	$ 1,998,779
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	4,280,027	4,128,980	3,989,081
Cost of removal of utility plant net	(279,620)	(229,670)	(27,534)
Loss on disposal of property	33,590		
Gain on sale of short-term investments	(8,540)		
Change in over/under recovery of gas costs	(3,842,557)	1,141,538	364,268
Deferred taxes and investment tax credits	(194,261)	(596,789)	681,386
Other noncash items net	144,013	213,245	(101,736)
Changes in assets and liabilities which provided (used) cash:			
Accounts receivable and customer deposits net	(1,184,724)	(500,591)	(1,408,206)
Inventories, gas in storage and prepaid gas	(5,772,211)	(1,364,866)	(5,735,169)
Other current assets	1,289,474	(964,203)	21,834
Accounts payable and accrued expenses	7,712,283	1,009,618	2,229,747
Refunds from suppliers due customers	(17,338)	(20,028)	(9,569)
Total adjustments	2,160,136	2,817,234	4,102
Net cash provided by continuing operating activities	5,548,069	4,877,001	2,002,881
Net cash (used in) provided by discontinued operations	(34,174)	(2,750,906)	2,514,860
Net cash provided by operating activities	5,513,895	2,126,095	4,517,741
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant and nonutility property	(7,427,304)	(7,925,948)	(6,774,991)
Proceeds from disposal of utility and nonutility property	90,557	31,345	15,492
Purchase of short-term investments		(4,991,460)	
Proceeds from sale of short-term investments	5,000,000		
Net cash used in continuing investing activities	(2,336,747)	(12,886,063)	(6,759,499)
Net cash provided by (used in) investing activities of discontinued operations	731,711	26,514,169	(1,242,558)
Net cash (used in) provided by investing activities	(1,605,036)	13,628,106	(8,002,057)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt		2,000,000	8,000,000
Retirement of long-term debt and capital leases	(19,987)	(6,357,372)	(105,126)
Net borrowings under line-of-credit agreements	(1,080,000)	(1,125,000)	(3,124,000)
Proceeds from issuance of common stock	823,417	1,398,362	816,981
Cash dividends paid	(11,743,988)	(2,344,972)	(2,255,571)
Net cash (used in) provided by financing activities	(12,020,558)	(6,428,982)	3,332,284

NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(8,111,699)	9,325,219	(152,032)
CASH AND CASH EQUIVALENTS Beginning of year	9,461,217	135,998	288,030
CASH AND CASH EQUIVALENTS End of year	$ 1,349,518	$ 9,461,217	$ 135,998

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2005, 2004 AND 2003

	2005	2004	2003
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION:			
Cash paid during the year for:			
Interest	$ 2,131,430	$ 2,076,895	$ 2,145,317
Income taxes net of refunds	$ 912,844	$ 10,237,991	$ 1,254,623

Noncash transactions:

In 2005, 2004 and 2003, the Company entered into derivative price swaps, caps, and collar arrangements for the purpose of hedging the cost of natural gas and propane. In accordance with hedge accounting requirements, the underlying derivatives were marked to market with the corresponding non-cash impacts to the consolidated balance sheets:

	2005	2004	2003
Unrealized gain (loss) on marked-to-market transactions	$ 86,962	$ 245,908	$ (2,099,155)
Under (over) recovery of gas costs		(70,150)	1,630,150
Deferred tax asset (liability)	(33,011)	(66,718)	180,212

Subsequent to September 30, 2005, the Company executed a $15,000,000 five-year intermediate note with provision for annual renewals for five years thereafter for Roanoke Gas Company and a $2,000,000 31-month note for Bluefield Gas Company to refinance currently maturing debt, a portion of the line of credit balances and long-term debt. A $10,000,000 reclassification from current maturities of long-term debt and a $4,000,000 reclassification from borrowings under lines-of-credit were made to long-term debt.

In 2005, the Company recorded a minimum pension liability associated with its defined pension plan resulting in the following non-cash impact to the balance sheet:

Deferred tax liability	(238,366)
Accrued Expenses	627,278

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2005, 2004, AND 2003

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 (the Company); Roanoke Gas Company; Bluefield Gas Company; Diversified Energy Company, operating as Highland Energy; and RGC Ventures, Inc. of Virginia, operating as Application Resources. Roanoke Gas Company and Bluefield Gas Company are natural gas utilities, which distribute and sell natural gas to residential, commercial and industrial customers within their service areas. Highland Energy brokers natural gas to several industrial transportation customers of Roanoke Gas Company and Bluefield Gas Company. Application Resources provides information system services to software providers in the utility industry.

The primary business of the Company is the distribution of natural gas to residential, commercial and industrial customers in Roanoke, Virginia; Bluefield, Virginia; Bluefield, West Virginia; and the surrounding areas. The Company distributes natural gas to its customers at rates regulated by the State Corporation Commission in Virginia (SCC) and the Public Service Commission in West Virginia (PSC).

Diversified Energy Company operated an unregulated propane operation under the name Highland Propane Company. As discussed in Note 2, the Company exited the propane business in July 2004 when substantially all of the assets of Highland Propane Company were sold. The results of operations for propane activities are reflected in the discontinued operations line of the accompanying consolidated statements of income and comprehensive income with the corresponding gain on disposition of assets.

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

The amounts recorded by the Company as regulatory assets and regulatory liabilities are as follows:

	September 30	
	2005	2004
Regulatory assets:		
Under-recovery of gas costs	$ 2,248,410	$ 580,166
Bad debt expense deferral	17,609	123,265
Line break expense deferral	158,805	196,113
Other	58,641	49,021
Total regulatory assets	$ 2,483,465	$ 948,565
Regulatory liabilities:		
Asset retirement obligation	$ 6,967,622	$ 6,197,549
Over-recovery of gas costs		2,174,313
Refunds from suppliers due customers	4,954	22,292
Total regulatory liabilities	$ 6,972,576	$ 8,394,154

During 2002, the Company reached an agreement with the regulatory staff of the SCC that provided for the deferral of $316,966 of bad debt expense to be amortized over a three-year period beginning in December 2002.

During 2003, the Company received authorization from the PSC to defer the costs of restoring gas service attributable to a natural gas line break in January 2003. The Company began recovering these costs through rates in December 2003.

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 asset retirement obligations. 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 with annual composite rates ranging up to 17% for utility property. Depreciable lives for non-utility property range from 3 to 40 years. The annual composite rates for utility property are determined by periodic depreciation studies. A depreciation study was completed and new rates were approved by the SCC on the Roanoke Gas utility plant assets. These new depreciation rates were effective January 1, 2004.

The composite rates are comprised of two components, one based on average service life and one based on cost of removal. Therefore, the Company accrues estimated cost of removal of long-lived assets through depreciation expense. Removal costs are not a legal obligation as defined by SFAS No. 143 but rather the result of cost-based regulation and accounted for under the provisions of SFAS No. 71. 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. Our reviews have not resulted in a material effect on results of operations or financial condition.

Cash, Cash Equivalents and Short-Term Investments 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. Short-term investments include commercial paper with original maturities greater than three months and less than one year which are valued at cost which approximates fair market value.

Inventories Inventories consist of natural gas in storage and materials. Inventories are recorded 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. The Company accrues estimates for natural gas delivered to customers not yet billed during the accounting period. The Company recognizes revenue when gas is delivered. The amounts of unbilled revenue receivable included in accounts receivable on the consolidated balance sheets at September 30, 2005 and 2004 were $1,736,976 and $1,235,833, 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 federal income tax return.

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

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

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

Reclassifications Certain prior period amounts have been reclassified to conform to current year presentation. Specifically, the Company reclassified certain financial statement items for 2004 to reflect the effect of discontinued operations discussed in Note 2. The Company also reclassified its liquefied natural gas inventory (LNG) for 2004 from inventory to gas in storage to place it on a basis consistent with the current year.

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. 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 and the diluted average common shares is provided below:

	Year Ended September 30		
	2005	2004	2003
Weighted average common shares	2,079,851	2,027,908	1,983,970
Effect of dilutive securities:			
Options to purchase common stock	13,264	14,404	5,490
Diluted average common shares	2,093,115	2,042,312	1,989,460

Stock option awards to purchase approximately 110 shares as of September 30, 2003 were not included in the computation of diluted earnings per share because inclusion of these shares would have been antidilutive as the option exercise prices were greater than the shares market prices during the period.

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

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

Prior to the sale of the propane operations, the Company has historically entered into futures, swaps and caps for the purpose of hedging the price of propane in order to provide price stability during the winter months. During the fiscal year ended September 30, 2004, the Company realized gains on derivative swap arrangements of $99,747 compared to a $471,184 gain in 2003. The hedges qualified as cash flow hedges; therefore, changes in the fair value are reported in other comprehensive income.

In addition, the Company has historically entered into futures, 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 under-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. Both the Virginia State Corporation Commission and the West Virginia Public Service Commission currently allow for full recovery of prudent costs associated with natural gas purchases, and any additional costs or benefits associated with the settlement of these instruments will be passed through to customers when realized. Due to the volatility and uncertainty in the natural gas market, the Company had not entered into any derivative contracts as of September 30, 2005.

The Company also entered into an interest rate swap related to the $8,000,000 note issued in November 2002. The swap essentially converted the three-year floating rate note into fixed rate debt with a 4.18% interest rate. The swap qualifies as a cash flow hedge with changes in fair value reported in other comprehensive income.

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

Other Comprehensive Income A summary of other comprehensive income and financial instrument activity is provided below:

	Propane Derivatives	Interest Rate Swap	Minimum Pension Liability	Total
Year Ended September 30, 2005				
Unrealized gains (losses)	$	$ 54,634	$ (627,278)	$ (572,644)
Income tax (expense) benefit		(20,739)	238,366	217,627
Net unrealized gains (losses)		33,895	(388,912)	(355,017)
Transfer of realized losses to income		32,328		32,328
Income tax benefit		(12,272)		(12,272)
Net transfer of realized losses to income		20,056		20,056
Net other comprehensive income (loss)	$	$ 53,951	$ (388,912)	$ (334,961)
Fair value of marked to market transactions	$	$ 13,606	$	$ 13,606
Accumulated comprehensive income (loss)	$	$ 8,441	$ (388,912)	$ (380,471)

	Propane Derivatives	Interest Rate Swap	Minimum Pension Liability	Total
Year Ended September 30, 2004				
Unrealized gains	$ 99,747	$ 16,292	$	$ 116,039
Income tax expense	(38,852)	(6,185)		(45,037)
Net unrealized gains	60,895	10,107		71,002
Transfer of realized (gains) losses to income	(99,747)	159,466		59,719
Income tax expense (benefit)	38,852	(60,533)		(21,681)
Net transfer of realized (gains) losses to income	(60,895)	98,933		38,038
Net other comprehensive income	$	$ 109,040	$	$ 109,040
Fair value of marked to market transactions	$	$ (73,356)	$	$ (73,356)
Accumulated comprehensive loss	$	$ (45,510)	$	$ (45,510)

	Propane Derivatives	Interest Rate Swap	Minimum Pension Liability	Total

Year Ended September 30, 2003				
Unrealized gains (losses)	$ 251,293	$ (364,063)	$	$ (112,770)
Income tax (expense) benefit	(97,879)	138,199		40,320
Net unrealized gains (losses)	153,414	(225,864)		(72,450)
Transfer of realized (gains) losses to income	(471,184)	114,949		(356,235)
Income tax expense (benefit)	183,527	(43,635)		139,892
Net transfer of realized (gains) losses to income	(287,657)	71,314		(216,343)
Net other comprehensive loss	$ (134,243)	$ (154,550)	$	$ (288,793)

Stock-Based Compensation The Company adopted the disclosure provisions of SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* an amendment of SFAS No. 123. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement requires that companies follow the prescribed format and provide the additional disclosures in their annual reports.

The Company applies the recognition and measurement principles of Accounting Principle Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for RGC Resources, Inc. Key Employees Stock Option Plan (Plan). No stock-based employee compensation expense is reflected in net income as all options granted under the Plan had an exercise price equal to the market value of the underlying common stock on the date of the grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to the options granted under the Plan. No options were granted in fiscal 2005 and 2004.

	Twelve Months Ended September 30		
	2005	**2004**	**2003**
Net income as reported	$ 3,506,906	$ 12,934,013	$ 3,528,389
Deduct: Total stock-based employee compensation expense determined under fair value method for all awards net of tax			(19,747)
Proforma net income	$ 3,506,906	$ 12,934,013	$ 3,508,642
Earnings per share as reported:			
Basic	$ 1.69	$ 6.38	$ 1.78
Diluted	$ 1.68	$ 6.33	$ 1.77
Earnings per share pro forma:			
Basic	$ 1.69	$ 6.38	$ 1.77
Diluted	$ 1.68	$ 6.33	$ 1.76

New Accounting Standards In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the Financial Accounting Standards Board (FASB) in FASB Staff Position 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003*, the Company elected to defer accounting for the effects of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position (FSP) 106-2. The Company elected the prospective method of recording the effects of this FSP; therefore, it was effective for the Company in the fourth quarter of fiscal 2004. FSP 106-2 results in the recognition of lower other postretirement employment benefit costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. As a result of the Medicare Act, the Company s accumulated postretirement benefit obligation was reduced by approximately $1.2 million at September 30, 2004.

Subsequent to September 30, 2005, the Company has further evaluated its options as it relates to the application of Medicare Part D. Beginning in January 2006, the Company will drop drug coverage under its medical plan for Medicare eligible retirees. In its place, the Company will provide eligible retirees with a reimbursement of premiums paid to a qualified prescription drug provider (PDP) whereby the PDP will provide the retiree with prescription drug coverage. Under the PDP, retirees have the ability to obtain drug coverage comparable to the coverage previously provided under the medical plan. This plan change will result in the Company s medical plan not being actuarially equivalent to Medicare Part D. However, the change in the plan is not expected to have a material impact on the accumulated postretirement benefit obligation and future expense due to the expected cost reductions under the revised plan as compared to the reductions attributable to the subsidy provisions available to actuarially equivalent plans.

The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* on October 1, 2002. SFAS No. 143 requires the reporting at fair value of a legal obligation associated with the retirement of tangible long-lived assets that result from acquisition, construction or development. Management has determined that the Company has no material legal obligations for the retirement of its assets. However, the Company provides a provision, as part of its depreciation expense, for the ultimate cost of asset retirements and removal. Removal costs are not a legal obligation as defined by SFAS No. 143 but rather the result of cost-based regulation and therefore accounted for under the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* Upon adoption of SFAS No. 143, the Company classified removal costs that do not have an associated legal retirement obligation as a regulatory liability, in accordance with regulatory treatment. The adoption of this statement had no effect on results of operations.

The Company adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* on October 1, 2002. SFAS No. 144 supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.* The new rules retain many of the fundamental recognition and measurement provisions, but significantly change the criteria for classifying an asset as held-for-sale and for accounting for discontinued operations. The adoption did not have a material impact on the Company s financial position or results of operation.

In January 2003, the FASB issued Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities,* which significantly changed the consolidation requirements for special purpose entities and similar entity structures. In December 2003, the FASB issued Interpretation No. 46R, *Consolidation of Variable Interest Entities-An Interpretation of ARB No. 51,* which supercedes and amends the provisions of FIN No. 46. The Company has no relationship with variable interest entities as defined by Interpretation No. 46; therefore, the adoption of this Interpretation had no effect on the Company s financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* The Company does not have any such debt or equity instruments as defined in SFAS No. 150; therefore, the implementation of the statement had no effect on the Company s financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment*, a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. This statement eliminates the alternative to use Accounting Principles Board s Opinion No. 25, *Accounting for Stock Issued to Employees*, intrinsic value method of accounting that was previously allowed under Statement 123. This statement requires entities to recognize the cost of employee services received in exchange for awards of equity instruments on the grant-date fair value of those awards. The effective date of this statement corresponds with fiscal years beginning after June 15, 2005, which would be October 1, 2005 for the

Company. As of September 30, 2005, only 2,000 options were available for grant under the Key Employee Stock Option Plan; therefore, the Company does not expect the adoption of this statement to have a material impact on the Company s financial position or results of operations. See Note 9 for disclosures related to the Key Employee Stock Option Plan.

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143*. Diverse accounting practices had developed with respect to the timing of liability recognition of legal obligations associated with the retirement of a tangible long-lived asset when the timing and/or method of settlement of the obligation are conditional on a future event. FIN No. 47 provided clarification when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This interpretation is effective for the Company September 30, 2006. The Company has not completed its evaluation of this interpretation and has not yet determined the impact on the Company s financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3*. This statement applies to all voluntary changes in accounting principle by requiring retrospective application of the change in accounting principle to all prior period financial statements presented. Retrospective application is defined as the application of a different accounting principle to prior accounting periods as if that principle had always been used. Previously, such changes were reflected in the current financial statements as a cumulative effect of change in accounting principle. The intent of the statement is to improve financial reporting by improving comparability of financial statements between periods. The effective date of this statement is for fiscal years beginning after December 15, 2005. This statement does not have a current effect on the Company s financial statements but will affect the Company s future reporting of changes in accounting principles, if any.

2. DISCONTINUED OPERATIONS

On July 12, 2004, Resources sold the propane assets of its subsidiary, Diversified Energy Company, d/b/a Highland Propane Company (Diversified), for approximately $28,500,000 in cash to Inergy Propane, LLC (Acquiror). The sale of assets encompassed all propane plant assets (with the exception of a limited number of specific assets being retained by Diversified), the name Highland Propane, customer accounts receivable, propane gas inventory and inventory of propane related materials. The Company realized a gain of approximately $9,500,000 on the sale of assets, net of income taxes.

Concurrent with the sale of assets, the Company entered into an agreement with Acquiror by which the Company would continue to provide the use of office, warehouse and storage space, and computer systems and office equipment and the utilization of Company personnel for billing, propane delivery and related services for the term of one year with an option for an additional year. The Acquiror notified the Company of its intent not to extend the remaining portions of the agreement and to allow the contract to expire in July 2005 with the exception of a one year lease agreement for access to the storage yard in Bluefield, West Virginia. For the year ended September 30, 2005, the Company realized approximately $451,000 in other revenues and $266,000 in other margin attributable to this agreement.

The asset purchase agreement did not include land and buildings owned by Diversified. Acquiror leased 10 parcels of real estate consisting of bulk storage facilities and office space from Diversified with an option to purchase such parcels. Prior to the end of June 2005, the Acquiror executed the option to purchase the real estate and closed on all 10 parcels. The Company realized a net gain on the sale of real estate of approximately $153,000. The operations associated with the real estate and corresponding gain have been classified as Discontinued Operations in accordance with the provisions of SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets*. The discontinued operations related to the sale of the real estate in June 2005 and sale of assets in 2004 is provided as follows:

	September 30		
	2005	**2004**	**2003**
Discontinued Operations:			
Pretax operating income	$ 39,366	$ 11,570	$
Gain on sale of assets	153,147		
Income tax	(73,540)	(4,535)	
Income from operations discontinued in 2005	118,973	7,035	
Income from operations discontinued in 2004		10,867,211	1,529,610
Discontinued operations	$ 118,973	$ 10,874,246	$ 1,529,610

The Company used the proceeds from the July 2004 sale of the propane assets to provide shareholders with a special $4.50 per share dividend and to retire corporate debt.

3. FINANCIAL INFORMATION BY BUSINESS SEGMENTS

Operating segments are defined as components of an enterprise for which separate financial information is available and is evaluated regularly by the chief decision maker in deciding how to allocate resources and assess performance. The Company uses gross margin to assess segment performance.

The reportable segments of the Company disclosed herein are as follows:

Gas Utilities The natural gas segment of the Company generates revenue from its tariff rates, under which it provides distribution energy services for its residential, commercial, and industrial customers.

Energy Marketing The energy marketing segment generates revenue through the sale of natural gas to transportation customers of Roanoke Gas Company and Bluefield Gas Company.

Parent and Other The other segment includes appliance services, information system services, and certain corporate eliminations.

Information related to the segments of the Company is detailed below:

	Gas Utilities	Energy Marketing	Parent and Other	Consolidated Total
Year Ended September 30, 2005				
Operating revenues	$ 99,196,587	$ 21,571,120	$ 880,080	$ 121,647,787
Gross margin	24,263,694	391,181	497,127	25,152,002
Operations, maintenance, and general taxes	13,359,975	59,761	189,718	13,609,454
Depreciation and amortization	4,025,729		3,388	4,029,117
Operating income	6,877,990	331,420	304,021	7,513,431
Other expenses net	113,996		(53,578)	60,418
Interest expense	2,023,913		1,380	2,025,293
Income before income taxes	4,740,081	331,420	356,219	5,427,720
As of September 30, 2005				
Total assets	$ 109,132,380	$ 2,554,763	$ 1,876,273	$ 113,563,416
Gross additions to long-lived assets	7,427,304			7,427,304

	Gas Utilities	Energy Marketing	Parent and Other	Consolidated Total
Year Ended September 30, 2004				
Operating revenues	$ 83,703,964	$ 18,810,525	$ 621,005	$ 103,135,494
Gross margin	22,833,506	254,716	292,872	23,381,094
Operations, maintenance, and general taxes	13,926,929	49,236	331,251	14,307,416
Depreciation and amortization	3,850,198		40,943	3,891,141
Operating income	5,056,379	205,480	(79,322)	5,182,537
Other expenses net	80,940		(61,319)	19,621
Interest expense	1,883,736			1,883,736
Income before income taxes	3,091,703	205,480	(18,003)	3,279,180
As of September 30, 2004				
Total assets*	$ 97,164,310	$ 2,320,974	$ 15,487,272	$ 114,972,556
Gross additions to long-lived assets	7,897,772		28,176	7,925,948

* The Parent and Other Segment includes $12,962,171 in cash and cash equivalents and short-term investments to pay the $ 4.50 per share dividend from the sale of the propane assets.

- 18 -

	Gas Utilities	Energy Marketing	Parent and Other	Consolidated Total
Year Ended September 30, 2003				
Operating revenues	$ 75,321,337	$ 13,091,137	$ 421,479	$ 88,833,953
Gross margin	21,425,681	285,042	207,502	21,918,225
Operations, maintenance, and general taxes	12,817,147	44,976	6,250	12,868,373
Depreciation and amortization	3,716,841		49,149	3,765,990
Operating income	4,891,693	240,066	152,103	5,283,862
Other expenses net	150,737			150,737
Interest expense	1,964,969			1,964,969
Income before income taxes	2,775,987	240,066	152,103	3,168,156
As of September 30, 2003				
Total assets	$ 89,196,889	$ 2,020,249	$ 13,147,595	$ 104,364,733
Gross additions to long-lived assets	6,774,401		590	6,774,991

One customer accounted for 5.3% and 5.5% of the Company s sales for 2005 and 2004, respectively. The same customer accounted for 8.6%, 8.3% and 8.7% of the Company s total accounts receivable at September 30, 2005, 2004 and 2003, respectively. Another customer accounted for 5.1% of the Company s total accounts receivable balance at September 30, 2005.

4. ALLOWANCE FOR DOUBTFUL ACCOUNTS

A summary of the changes in the allowance for doubtful accounts follows:

	Years Ended September 30		
	2005	2004	2003
Balances, beginning of year	$ 38,525	$ 163,900	$ 42,767
Provision for doubtful accounts	685,388	486,949	574,871
Recoveries of accounts written off	340,185	289,179	282,446
Accounts written off	(780,090)	(901,503)	(736,184)
Balances, end of year	$ 284,008	$ 38,525	$ 163,900

The allowance account at September 30, 2005 includes a $200,000 reserve related to a commercial customer that management believes will have difficulty in paying off its obligation.

5. BORROWINGS UNDER LINES-OF-CREDIT

The Company has available unsecured lines-of-credit with a bank for $28,000,000 as of September 30, 2005. These lines-of-credit will expire March 31, 2006. The Company anticipates being able to extend the lines-of-credit or pursue other options. The Company s available unsecured lines-of-credit vary during the year to accommodate its seasonal borrowing demands. Generally, the Company s borrowing needs are at their lowest in spring, increase during the summer and fall due to gas storage purchases and construction and reach their maximum levels in winter. Available limits under the line-of-credit agreements for the remaining term are as follows:

Effective	Available Line of Credit
September 30, 2005	$ 28,000,000
November 16, 2005	29,000,000
February 16, 2006	25,000,000

Subsequent to September 30, 2005, the Company executed a $15,000,000 note to refinance $8,000,000 of currently maturing debt, $4,000,000 line-of-credit balance, and $3,000,000 of outstanding debt due 2016. As the Company met the requirements of both the intent and ability to refinance, debt balances in the September 30, 2005 balance sheet were reclassified to reflect the substance of the transaction. The table below reflects the reclassification of $4,000,000 in outstanding lines-of-credit to long-term debt.

	2005	2004	2003
Lines of credit at year-end	$ 28,000,000	$ 24,000,000	$ 28,000,000
Outstanding balance at year-end	7,662,000	12,742,000	12,992,000
Highest month-end balances outstanding	18,116,000	20,904,000	20,184,000
Average month-end balances	9,677,000	10,559,000	10,104,000
Average rates of interest during year	3.15%	1.79%	1.99%
Average rates of interest on balances outstanding at year-end	4.42%	2.40%	1.70%

6. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30	
	2005	2004
Roanoke Gas Company:		
First Mortgage notes payable, at 7.804%, due July 1, 2008	$ 5,000,000	$ 5,000,000
Collateralized term debentures, at 9.625% due October 1, 2016	3,000,000	3,000,000
Unsecured senior notes payable, at 7.66%, with provision for retirement of $1,600,000 each year beginning December 1, 2014 through December 1, 2018	8,000,000	8,000,000
Obligations under capital leases, aggregate monthly payments of $2,924, through April 2005		19,987
Unsecured note payable, with variable interest rate based on 30-day LIBOR (3.86% at September 30, 2005) plus 100 basis point spread, with provision for retirement on November 30, 2005.	8,000,000	8,000,000
Bluefield Gas Company:		
Unsecured note payable with variable interest rate based on 30-day LIBOR (3.86% at September 30, 2005) plus 113 basis point spread, due November 21, 2005	2,000,000	2,000,000
Line-of-credit	4,000,000	
Total long-term debt	30,000,000	26,019,987
Less current maturities		(19,987)
Total long-term debt excluding current maturities	$ 30,000,000	$ 26,000,000

The above debt obligations contain various provisions, including a minimum interest charge coverage ratio and limitations on debt as a percentage of total capitalization. The obligations also contain 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, 2005 and 2004. At September 30, 2005, approximately $10,163,000 of retained earnings were available for dividends.

Subsequent to September 30, 2005, Roanoke Gas Company entered into an unsecured 5 year variable rate note with provisions for annual renewal after the initial five year term in the amount of $15,000,000. The proceeds of this note were used to refinance the $8,000,000 unsecured note due November 30, 2005 and $4,000,000 in outstanding line of credit balance. The remainder of the proceeds were used to call the $3,000,000 collateralized term debentures due in 2016 including a call premium of $206,250. The Company plans to apply the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, and defer and amortize the call premium over the life of the new debt. Also subsequent to September 30, 2005, Bluefield Gas Company entered into an unsecured 31 month variable rate note in the amount of $2,000,000. The proceeds of this note were used to refinance the $2,000,000 unsecured note due November 2005. The Company entered into an interest rate swap agreement on the Roanoke Gas Company note for the purpose of fixing the interest rate over the term of the note. As a result of these refinancings, the Company reclassified

$10,000,000 from current maturities of long-term debt and $4,000,000 from borrowings under lines-of-credit to long-term debt.

The aggregate annual maturities of long-term debt, subsequent to September 30, 2005, are as follows:

Years Ended September 30	
2006	$
2007	
2008	7,000,000
2009	
2010	
Thereafter	23,000,000
Total	$ 30,000,000

7. INCOME TAXES

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

	Years Ended September 30		
	2005	**2004**	**2003**
Current income taxes:			
Federal	$ 1,838,868	$ 175,465	$ 396,468
State	363,268	284,731	122,044
Total current income taxes	2,202,136	460,196	518,512
Deferred income taxes:			
Federal	(119,974)	885,112	615,585
State	(8,237)	(91,757)	69,486
Total deferred income taxes	(128,211)	793,355	685,071
Amortization of investment tax credits	(34,138)	(34,138)	(34,206)
Total income tax expense	$ 2,039,787	$ 1,219,413	$ 1,169,377

Income tax expense for the years ended September 30, 2005, 2004, and 2003 differed from amounts computed by applying the U.S. Federal income tax rate of 34%, 35%* and 34%, respectively, to earnings before income taxes as a result of the following:

	Years Ended September 30		
	2005	**2004**	**2003**
Income before income taxes	$ 5,427,720	$ 3,279,180	$ 3,168,156
Income tax expense computed at statutory rate of 34% in 2005, 35% in 2004 and 34% in 2003	$ 1,845,425	$ 1,147,713	$ 1,077,173
Increase (reduction) in income tax expense resulting from:			
State income taxes, net of federal income tax benefit	234,320	125,433	126,410
Amortization of investment tax credits	(34,138)	(34,138)	(34,206)
Other net	(5,820)	(19,595)	
Total income tax expense	$ 2,039,787	$ 1,219,413	$ 1,169,377

* The gain on sale of propane assets in 2004 resulted in an increase in the federal income tax rate to 35%. In 2005, the federal tax rate returned to 34% as taxable income returned to normal levels.

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

	September 30	
	2005	**2004**
Deferred tax assets:		
Allowance for uncollectibles	$ 107,955	$ 14,745
Accrued medical insurance	7,616	131,046
Accrued pension and post-retirement medical benefits	1,627,502	1,591,655
Accrued vacation	195,653	187,682
Over recovery of gas costs		593,651
Costs of gas held in storage	819,204	720,449
Accrued gas costs	2,079,381	
Other	340,714	286,856
Valuation allowance	(41,479)	(24,488)
Total deferred tax assets	5,136,546	3,501,596
Deferred tax liabilities:		
Utility plant	7,263,809	6,858,145
Under recovery of gas costs	863,808	
Total deferred tax liabilities	8,127,617	6,858,145
Net deferred tax liability	$ 2,991,071	$ 3,356,549

The Company recorded a valuation allowance to reflect the estimated amount of deferred tax assets associated with Diversified Energy s operation in West Virginia, which may not be realized due to the uncertain availability of future taxable income. As Diversified Energy files a stand alone state income tax return in West Virginia, the sale of propane assets essentially eliminated any future West Virginia taxable income. The Company also recorded a partial valuation allowance on the Bluefield Gas Company Net Operating Loss carryforward (NOL), which is included in Other in the table above. In its evaluation, management estimated that a portion of the NOL carryforward may not be realized for state income tax purposes. The valuation allowance related only to the state deferred tax asset. As the Company files a consolidated federal income tax return, management expects to be able to fully realize the federal portion of the deferred tax asset.

8. EMPLOYEE BENEFIT PLANS

The Company sponsors both a defined benefit pension plan and a postretirement plan (Plans). The defined benefit plan covers substantially all employees and fully vests 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. The Company uses a June 30 measurement date for both of these plans. The following tables set forth the benefit obligation, fair value of plan assets, and the funded status of the Plans; amounts recognized in the Company s financial statements and the assumptions used:

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 10,508,002	$ 10,457,455	$ 7,349,726	$ 9,350,513
Service cost	327,424	381,588	128,972	192,088
Interest cost	631,731	613,397	444,267	528,218
Participant contributions			41,616	49,065
Actuarial (gain) loss	2,622,066	(509,059)	2,236,085	(2,326,103)
Diversified sale	(158,553)			
Benefit payments	(441,917)	(435,379)	(587,813)	(444,055)
Benefit obligation at end of year	$ 13,488,753	$ 10,508,002	$ 9,612,853	$ 7,349,726
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 7,722,817	$ 6,589,170	$ 3,185,559	$ 2,536,425
Actual return on plan assets	443,379	769,026	234,945	385,124
Employer contributions	700,000	800,000	772,000	709,000
Participant contributions			41,616	49,065
Tax payments			(60,000)	(50,000)
Benefit payments	(441,917)	(435,379)	(587,813)	(444,055)
Fair value of plan assets at end of year	$ 8,424,279	$ 7,722,817	$ 3,586,307	$ 3,185,559
Reconciliation of funded status:				
Funded status	$ (5,064,474)	$ (2,785,185)	$ (6,026,546)	$ (4,164,167)
Unrecognized actuarial gain (loss)	4,207,141	1,677,521	2,157,811	(89,139)
Unrecognized transition obligation			1,898,400	2,135,700
Contributions made between the measurement date and fiscal year-end	200,000	150,000	896,830	772,000
Net amount recognized	$ (657,333)	$ (957,664)	$ (1,073,505)	$ (1,345,606)
Amounts recognized in the balance sheets consist of:				
Accrued benefit liability	$ (1,284,611)	$ (957,664)		
Accumulated other comprehensive income	627,278			
Net amount recognized	$ (657,333)	$ (957,664)		

The provisions of SFAS No. 87, *Employers Accounting for Pensions*, required the Company to record an additional minimum liability of $627,278 at September 30, 2005. This liability represents the amount by which the accumulated benefit obligation exceeds the sum of the fair market value of plan assets and the recorded accrued pension liability. The $627,278 is reflected in other comprehensive income (loss) and accumulated other comprehensive income (loss), net of tax. A reconciliation of other comprehensive income is included in Note 1.

The Company amortizes the unrecognized transition obligation over 20 years.

The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit cost of the pension and other postretirement plan for 2005, 2004 and 2003:

	Pension Benefits			Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
Assumptions related to benefit obligations:						
Discount rate	5.25%	6.25%	6.00%	5.25%	6.25%	6.00%
Expected rate of compensation increase	5.00%	5.00%	5.00%	N/A	N/A	N/A
Assumptions related to benefit costs:						
Discount rate	6.25%	6.00%	7.00%	6.25%	6.00%	7.00%
Expected long-term rate of return on plan assets	7.50%	8.00%	8.00%	7.00%	7.00%	7.00%
Expected rate of compensation increase	5.00%	5.00%	5.00%	N/A	N/A	N/A

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

	Pension Plan			Postretirement Plan		
	2005	2004	2003	2005	2004	2003
Components of net periodic benefit cost:						
Service cost	$ 327,424	$ 381,588	$ 300,867	$ 128,972	$ 192,088	$ 171,508
Interest cost	631,731	613,397	602,282	444,267	528,218	555,424
Expected return on plan assets	(571,881)	(508,401)	(510,138)	(185,810)	(134,519)	(121,640)
Amortization of unrecognized transition obligation			1,133	237,300	237,300	237,300
Recognized loss	62,395	123,553	23,425		91,641	59,908
Net periodic benefit cost	$ 449,669	$ 610,137	$ 417,569	$ 624,729	$ 914,728	$ 902,500

The net periodic costs for postretirement benefits decreased during the fiscal year ended September 30, 2005 due to the implementation of FASB Staff Position 106-2. See discussion in Note 1.

Actuarial estimates for the postretirement benefit plan assumed a weighted average annual rate increase in the per capital costs of covered health care benefits; (medical trend rate) were 9%, 10% and 10% for 2005, 2004 and 2003, respectively. The rates were assumed to decrease gradually to 4.75% by the year 2010 and remain at that level thereafter. Assumed medical trend rates have a significant effect on the amounts reported. A 1% point change in assumed healthcare cost trend rates would have the following effects:

	2005
One percentage point increase:	
Aggregate of service and interest cost	$ 86,495
Accumulated postretirement benefit obligation	1,243,571
One percentage point decrease:	
Aggregate of service and interest cost	$ (69,354)
Accumulated postretirement benefit obligation	(1,005,538)

The accumulated benefit obligation for the defined benefit pension plan was $9,908,890 and $7,778,749 in 2005 and 2004, respectively.

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

	Pension Plan		Postretirement Benefit Plan	
	Target	2005	Target	2005
Asset category:				
Equity securities	50%-70%	63%	35%-65%	55%
Debt securities	30%-50%	34%	35%-65%	40%
Other	0%-20%	3%	0%-20%	5%

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 Company expects to contribute $800,000 to its pension plan and $700,000 to its postretirement benefit plan in 2006.

The following table reflects expected future benefit payments.

		Postretirement Benefit Plan		
Fiscal year ending September 30	**Pension Plan**	**Gross Payments**	**Subsidy**	**Net**
2006	$ 447,609	$ 517,209	$ (28,394)	$ 488,815
2007	442,036	534,735	(58,720)	476,015
2008	442,695	554,817	(62,300)	492,517
2009	450,767	578,639	(66,466)	512,173
2010	463,717	596,301	(70,523)	525,778
2011-2015	2,675,726	3,236,852	(407,288)	2,829,564

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 Plan, limited to a maximum annual amount as set periodically by the Internal Revenue Service. The Company made annual matching contributions to the plan for fiscal years ended September 30, 2003 and 2002 and through December 31, 2003, based on 70% of the net participants first 6% in contributions. Beginning in January 2004, that matching formula changed to match 100% on the participants first 3% of contributions and 50% on the next 3% of contributions. Company matching contributions were $229,441, $254,121, and $228,737 for 2005, 2004 and 2003, respectively.

9. COMMON STOCK OPTIONS

The Company s stockholders approved the RGC Resources, Inc. Key Employee Stock Option Plan (KESOP). 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, 2005, the number of shares available for future grants under the KESOP is 2,000 shares.

The aggregate number of shares under option pursuant to the RGC Resources, Inc. Key Employee Stock Option Plan are as follows:

	Number of Shares	Weighted-Average Exercise Price	Option Price Per Share
Options outstanding, September 30, 2002	60,000	$ 19.319	$ 15.500-$20.875
Options granted	13,500	18.100	
Options exercised			
Options expired	(2,000)		
Options outstanding, September 30, 2003	71,500	$ 19.049	$ 15.500-$20.875
Options exercised	(18,000)		
Options expired			
Options outstanding, September 30, 2004	53,500	$ 19.288	$ 15.500-$20.875
Options exercised	(7,500)		
Options expired			
Options outstanding, September 30, 2005	46,000	$ 19.545	$ 16.875-$20.875

	Shares	Remaining Life (Years)	Exercise Price
	4,000	1.1	16.875
	8,500	2.3	20.625
	11,000	4.2	20.875
	7,000	5.2	19.250
	9,000	6.2	19.360
	6,500	7.2	18.100
Weighted average	46,000	4.5	$ 19.545

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, 2005 and 2004. No options were granted in 2005 and 2004.

The per share weighted-average fair value of stock options granted during 2003 was $1.82 on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions.

	2003
Expected dividend yield	6.30%
Risk-free interest rate	3.70%
Expected volatility	26.60%
Expected life	10 years

10. RELATED-PARTY TRANSACTIONS

Certain of the Company s directors and officers are affiliated with companies that render services or sell products to the Company or are associated with companies that purchase natural gas from Resources energy marketing operations. Management believes such transactions are entered into on terms equivalent to normal business terms.

The Company purchased beeper, internet and telephone services of approximately $76,000, $97,000 and $91,000 in 2005, 2004 and 2003, respectively, from a telecommunications company in which Resources Chief Executive Officer served on the telecommunications company s board of directors. Management anticipates similar services will be provided to the Company in 2006.

The products sold to the Company include propane truck purchases and repair services of approximately $29,000 and $40,000 in 2004 and 2003, respectively, from a company whose president serves on Resources Board of Directors. Management does not anticipate that similar services and products will be provided to Resources in 2006 as most of these expenses were incurred by the discontinued propane operations.

In 2005, the Company sold natural gas through its unregulated energy marketing company for approximately $1,816,000 to a not for profit medical institution in which one of Resources newly elected directors serves as chief operating officer. As of September 30, 2005, approximately $187,000 is included in accounts receivable related to the natural gas service. Management anticipates that the Company will provide similar natural gas service through its energy marketing operations in 2006.

11. ENVIRONMENTAL MATTER

Both Roanoke Gas Company and Bluefield Gas Company operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the early 1950 s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. The extent of contaminants at these sites, if any, is unknown at this time. An analysis at the Bluefield Gas Company site indicates some soil contamination. The Company, with concurrence of legal counsel, does not believe any events have occurred requiring regulatory reporting. Further, the Company has not received any notices of violation or liabilities associated with environmental regulations related to the MGP sites and is not aware of any off-site contamination or pollution as a result of prior operations. Therefore, the Company has no plans for subsurface remediation at the MGP sites. Should the Company eventually 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. A stipulated rate case agreement between the Company and the West

Virginia Public Service Commission recognized the Company s right to defer MGP clean-up costs, should any be incurred, and to seek rate relief for such costs. If the Company eventually incurs costs associated with a required clean up of either MGP site, the Company anticipates recording a regulatory asset for such clean-up costs to be recovered in future rates. Based on anticipated regulatory actions and current practices, management believes that any costs incurred related to this matter will not have a material effect on the Company s financial condition or results of operations.

12. 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 its asset manager under the contract effective November 1, 2004 between Roanoke Gas Company and Bluefield Gas Company and the asset manager. The Company has chosen the 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 manager contract mentioned above, the Company designated the asset manager as agent for their storage capacity and all gas balances in storage as of October 31, 2004. The asset manager provides agency service and manages the utilization of storage assets and the corresponding withdrawals from injections to 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 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, 2005. 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.

Highland Energy, the unregulated energy marketing company, also contracts for the purchase of natural gas from suppliers for future deliveries. These commitments generally are for fixed volumes at fixed prices for the upcoming year.

The following schedule reflects the financial and volumetric obligations as of September 30, 2005 for each of the years presented:

	Fixed Price Contracts		**Market Price Contracts**
	Pipeline and Storage Capacity	**Natural Gas Contracts**	**Natural Gas Contracts (Decatherms)**
2006	$ 11,007,513	$ 7,483,137	2,373,302
2007	10,895,013	39,000	2,369,535
2008	10,737,513		338,505
2009	10,737,513		
2010	10,737,513		
2011-2020	50,650,568		

The Company purchased approximately $56,300,000 in gas under the new asset management contracts in fiscal 2005.

The Company has historically entered into derivative financial contracts for the purpose of hedging the price of natural gas. As of September 30, 2005, the Company had no outstanding derivative contracts for natural gas.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amount of cash and cash equivalents, temporary cash investments and borrowings under lines of credit are a reasonable estimate of fair value due to their short-term nature and because the rates of interest paid on borrowings under lines of credit approximate market rates.

The fair value of long-term debt is estimated by discounting the future cash flows of each issuance at rates currently offered to the Company for similar debt instruments of comparable maturities. The carrying amounts and approximate fair values for the years ended September 30, 2005 and 2004 are as follows:

	2005		2004	
	Carrying Amounts	Approximate Fair Value	Carrying Amounts	Approximate Fair Value
Long-term debt	$ 30,000,000	$ 31,667,266	$ 26,019,987	$ 29,302,836

Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of September 30, 2005 and 2004 are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly financial data for the years ended September 30, 2005 and 2004 is summarized as follows:

2005	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 34,652,352	$ 43,316,547	$ 20,838,353	$ 22,840,535
Gross margin	$ 7,298,017	$ 8,472,812	$ 4,988,119	$ 4,393,054
Operating income (loss)	$ 3,128,858	$ 3,850,118	$ 698,032	$ (163,577)
Net income (loss) from continuing operations	$ 1,617,286	$ 2,055,609	$ 126,771	$ (411,733)
Net income from discontinued operations	$ 8,109	$ 8,110	$ 102,754	$
Net income (loss)	$ 1,625,395	$ 2,063,719	$ 229,525	$ (411,733)

Basic earnings (loss) per share:								
Continuing operations	$	0.79	$	0.99	$	0.06	$	(0.21)
Discontinued operations	$		$	0.01	$	0.05	$	
Net income (loss)	$	0.79	$	1.00	$	0.11	$	(0.21)

2004	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 29,867,898	$ 39,721,044	$ 18,233,478	$ 15,313,074
Gross margin	$ 6,733,567	$ 8,212,985	$ 4,402,763	$ 4,031,779
Operating income (loss)	$ 2,344,645	$ 3,548,755	$ 11,530	$ (722,393)
Net income (loss) from continuing operations	$ 1,143,536	$ 1,875,448	$ (275,743)	$ (683,474)
Net income (loss) from discontinued operations	$ 455,867	$ 1,272,804	$ (236,921)	$ 9,382,496
Net income (loss)	$ 1,599,403	$ 3,148,252	$ (512,664)	$ 8,699,022
Basic earnings (loss) per share:				
Continuing operations	$ 0.57	$ 0.93	$ (0.13)	$ (0.35)
Discontinued operations	$ 0.23	$ 0.63	$ (0.12)	$ 4.62
Net income (loss)	$ 0.80	$ 1.56	$ (0.25)	$ 4.27

The pattern of quarterly earnings is the result of the highly seasonal nature of the business, as variations in weather conditions generally result in greater earnings during the winter months.

* * * * * *

CORPORATE OFFICE

RGC RESOURCES, INC.

519 Kimball Avenue, N.E.

P.O. Box 13007

Roanoke, VA 24030

(540) 777-4GAS (4427)

Fax (540) 777-2636

AUDITORS

DELOITTE & TOUCHE LLP

1100 Carillon Building

227 West Trade Street

Charlotte, NC 28202-1675

COMMON STOCK TRANSFER AGENT, REGISTRAR, DIVIDEND DISBURSING

Agent & Dividend Reinvestment Agent

WACHOVIA BANK, N.A.

Corporate Trust Group

1525 West W.T. Harris Boulevard - 3C3

Charlotte, NC 28262-8522

COMMON STOCK

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

DIRECT DEPOSIT OF DIVIDEND AND SAFEKEEPING OF STOCK CERTIFICATES

Shareholders can have their cash dividends deposited automatically into checking, saving 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, Wachovia Bank, N.A. of North Carolina.

10-K REPORT

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

DALE P. MOORE

Vice President and Secretary

RGC Resources, Inc.

P.O. Box 13007 Roanoke, VA 24030

(540) 777-3846

Access all 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, Wachovia Bank, N.A.

All other shareholder questions should be directed to:

RGC RESOURCES, INC.

Vice President and Secretary

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

FINANCIAL INQUIRIES

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

RGC RESOURCES, INC.

Vice President and Secretary

P.O. Box 13007 Roanoke, VA 24030

(540) 777-3846

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

519 Kimball Avenue, N.E.

P.O. Box 13007

Roanoke, VA 24030

www.rgcresources.com

Trading on NASDAQ as RGCO