RGC RESOURCES INC
Form ARS
December 12, 2012

JOHN B. WILLIAMSON, III

RGC Resources, Inc.

Chairman of the Board, President & CEO

To Our Shareholders:

I am pleased to report 2012 earnings of $4,296,745 or $0.92 per share outstanding. While it s a decline from last year, I consider it a solid performance considering the weather was over 20 percent warmer than normal and the economy remains anemic.

I am also pleased that your Board of Directors approved a $1.00 special dividend payable December 17, 2012, to shareholders of record on November 30, 2012. We have worked hard over the years to build a strong balance sheet. Combined with less financing needed for significantly lower cost gas inventory, that balance sheet strength provided an opportunity to distribute a portion of retained earnings to shareholders while maintaining a strong capital position. While we do not know what long-term tax rates will be, we believed it was in our shareholders best interest to make the special dividend while we were sure of the 15 percent income tax treatment of qualified dividends for individuals.

In addition to the special dividend, our Board of Directors approved an annualized dividend increase from $0.70 per share to $0.72 per share effective with the February 1, 2013, quarterly dividend payment. The February dividend will reflect 68 years of continuous quarterly dividend payments and 16 dividend increases in the past 17 years.

Average 2012 natural gas prices were at or near a 10-year low and the short and intermediate term price outlook is very positive for our customers. The Marcellous Miracle continues as the industry employs improved horizontal drilling and shale rock hydraulic fracturing technologies producing low cost supplies. The energy paradigm in North America has been transformed over the last five years as we have progressed from a period of high prices and long-term natural gas supply concerns to what now appears to be a future of long-term abundance and reasonably stable pricing.

As with most commodities, natural gas supply and pricing are subject to a variety of pressures. Natural gas pricing has been largely driven by weather demand, access to supply development areas, increasing electricity generation demand and regulatory impacts. Coal is rapidly being replaced by natural gas as the fuel of choice for electricity generation as a result of increased environmental regulation of coal burning for generation. Demand for natural gas in the manufacturing sector is also increasing as the comparative cost of alternative fuels increase. Despite growing demand, most industry literature indicates there will be ample natural gas supply to meet the need at reasonable prices. I remain optimistic that the industry will continue to reduce environmental impacts from improved gas drilling and production methods lessening the potential for overly prescriptive regulations that could negatively affect future supply costs.

We continue to aggressively replace the cast iron and bare steel pipeline in our own distribution system with plastic pipe, and where conditions or operating pressures warrant, coated steel pipe. After 20 years of a steady replacement program, we recently doubled our annual replacements efforts and now project to have all cast iron and bare steel pipe replaced by the end of 2018.

While the new-construction housing market in our service area remains weak, as generally has been the case nationally, we are experiencing modest customer growth, including conversion to natural gas of homes heated with fuel oil or electricity. Our active customer count increased by a half percent this year. We also experienced a modest increase in industrial deliveries as several of our larger customers increased their production levels. While difficult to predict, we anticipate similar

activity in 2013 assuming the U.S. economy does not follow Europe into recession, or go over the fiscal cliff.

We continue to be active in rate filings with the Virginia State Corporation Commission to ensure that costs associated with increased investment in replacement pipeline are recovered in a timely manner. In this period of very low interest rates, driven by Federal Reserve Bank monetary policy, rate regulators are tending to lower the authorized return on equity invested in utility plant. In our 2011 rate case, finalized in 2012, the authorized return on equity was lowered from 10.1 percent to 9.75 percent. We filed a new case in September 2012 seeking to restore the 10.1 percent equity return.

We announced a management succession plan on October 1, 2012. John D Orazio has been appointed President and CEO of Roanoke Gas Company, our largest and primary subsidiary. John has been my Chief Operating Officer since 2003 and I have confidence in his and the rest of our management team s abilities. To ensure a smooth transition, I am continuing as Chairman, President and CEO of RGC Resources, Inc., on a reduced time basis, until February 2014. As currently planned, assuming the transition goes as anticipated, I will step down as President and CEO of RGC Resources following the 2014 shareholder meeting, but will remain Chairman with a continuing senior advisory role as needed. It has been a privilege and personal pleasure to have been your CEO for the last 15 years. I look forward to a continuing role in the success of the Company and the safe, reliable and economical delivery of natural gas to our customers and a competitive return to our shareholders.

On behalf of our employees and the Board of Directors, I thank you for your interest in our operations and your continuing decision to own RGC Resources stock. I believe it remains a good time to invest in the natural gas distribution business and the Roanoke, Virginia, region.

Sincerely,

John B. Williamson, III

Chairman, President and CEO

SELECTED FINANCIAL DATA

YEAR ENDED SEPTEMBER 30,	2012	2011	2010	2009	2008
OPERATING REVENUES	**$ 58,799,687**	$ 70,798,871	$ 73,823,914	$ 82,184,473	$ 94,636,826
GROSS MARGIN	**26,933,097**	27,269,566	26,440,273	27,075,924	25,913,612
OPERATING INCOME	**8,786,535**	9,313,046	8,982,181	9,844,516	8,838,026
NET INCOME - CONTINUING OPERATIONS	**4,296,745**	4,653,473	4,445,436	4,869,010	4,257,824
NET LOSS - DISCONTINUED OPERATIONS					(36,690)
BASIC EARNINGS PER SHARE - CONTINUING OPERATIONS	**$ 0.92**	$ 1.01	$ 0.98	$ 1.09	$ 0.97
BASIC EARNINGS PER SHARE - DISCONTINUED OPERATIONS					(0.01)
CASH DIVIDENDS DECLARED PER SHARE	**0.700**	0.680	0.660	0.640	0.625
BOOK VALUE PER SHARE	**10.85**	10.55	10.18	10.00	9.89
AVERAGE SHARES OUTSTANDING	**4,647,439**	4,592,713	4,514,262	4,447,454	4,402,527
TOTAL ASSETS	**$ 129,756,338**	$ 125,549,049	$ 120,683,316	$ 118,801,892	$ 118,127,714
LONG-TERM DEBT (LESS CURRENT PORTION)	**13,000,000**	13,000,000	28,000,000	28,000,000	23,000,000
STOCKHOLDERS EQUITY	**50,682,930**	48,785,778	46,309,747	44,799,871	43,723,058
SHARES OUTSTANDING AT SEPT. 30	**4,670,567**	4,624,682	4,548,864	4,477,974	4,418,942

FORWARD LOOKING STATEMENTS

This report contains forward-looking statements that relate to future transactions, events or expectations. In addition, RGC Resources, Inc. (Resources or the Company) may publish forward-looking statements relating to such matters as anticipated financial performance, business prospects, technological developments, new products, research and development activities and similar matters. These statements are based on management s current expectations and information available at the time of such statements and are believed to be reasonable and are made in good faith. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements. In order to comply with the terms of the safe harbor, the Company notes that a variety of factors could cause the Company s actual results and experience to differ materially from the anticipated results or expectations expressed in the Company s forward-looking statements. The risks and uncertainties that may affect the operations, performance, development and results of the Company s business include, but are not limited to those set forth in the

following discussion and within Item 1A Risk Factors of this Annual Report on Form 10-K. All of these factors are difficult to predict and many are beyond the Company s control. Accordingly, while the Company believes its forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. When used in the Company s documents or news releases, the words anticipate, believe, intend, plan, estimate, expect, objective, projection, forecast, budget or similar words or future or conditional verbs such as will, would, should, can, could or may are intended to identify forward-looking statements.

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

MANAGEMENT S DISCUSSION AND ANALYSIS

OVERVIEW

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 57,900 residential, commercial and industrial customers in Roanoke, Virginia and the surrounding localities through its Roanoke Gas Company (Roanoke Gas) subsidiary. Resources also provides certain unregulated services through Roanoke Gas and utility consulting and information system services through RGC Ventures of Virginia, Inc., which operates as The Utility Consultants and Application Resources. The unregulated operations represent less than 3% of revenues and margins of Resources.

The utility operations of Roanoke Gas are regulated by the Virginia State Corporation Commission (SCC) which oversees the terms, conditions, and rates to be charged to customers for natural gas service, safety standards, extension of service, accounting and depreciation. The Company is also subject to federal regulation from the Department of Transportation in regard to the construction, operation, maintenance, safety and pipeline integrity of its transmission and distribution pipelines. The Federal Energy Regulatory Commission regulates the prices for the transportation and delivery of natural gas to the Company s distribution system and underground storage services. The Company is also subject to other regulations which are not necessarily industry specific.

The passage of health care reform as part of the Health Care and Education Reconciliation Act of 2010 and the Patient Protection and Affordable Care Act in addition to increased regulations related to the financial markets have resulted, and will result, in additional rules and regulations. The Company is continuing to evaluate the full impact of these laws and regulations and will continue to monitor the regulations as they are developed and implemented. Management does not expect these laws and resulting regulations to have a material impact on the Company s financial position, results of operations or cash flows.

The Company is committed to the safe and reliable delivery of natural gas to its customers. Since 1991, the Company has placed an emphasis on the renewal and replacement of its cast iron and bare steel natural gas distribution

pipelines. With recent regulatory actions placing a greater focus on pipeline safety, the Company has increased its efforts to complete its renewal and replacement program. Management anticipates replacing all remaining cast iron and bare steel pipe within the next six years.

The Company is also dedicated to the safeguarding of its information technology systems. These systems contain confidential customer, vendor and employee information as well as important financial data. There is risk associated with the unauthorized access of this information with a malicious intent to corrupt data, cause operational disruptions, or compromise information. Management believes it has taken reasonable security measures to protect these systems from cyber security attacks and other types of breaches; however, there can be no guarantee that a breach will not occur. In the event of a breach, the Company is prepared to execute its Security Incident Response Plan to reduce the impact of the incident. The Company also maintains cyber-insurance coverage to mitigate financial implications resulting from a potential breach of confidential information.

The SCC authorizes the rates and fees that the Company charges its customers for regulated natural gas service. These rates are designed to provide the Company with the opportunity to recover its gas and non-gas expenses and to earn a reasonable rate of return for shareholders. The Company s business is seasonal in nature and weather dependent as a majority of natural gas sales are for space heating during the winter season. Volatility in winter weather and the commodity price of natural gas can impact the effectiveness of the Company s rates in recovering its costs and providing a reasonable rate of return for its shareholders. Over the past several years, the Company has implemented certain approved rate mechanisms that reduce some of the volatility in earnings associated with variations in winter weather and the cost of natural gas.

Roanoke Gas has in place a weather normalization adjustment mechanism (WNA) based on a weather measurement band around the most recent 30-year temperature average. Because the SCC authorizes billing rates for the utility operations of Roanoke Gas based on normal weather, warmer than normal weather may result in the Company failing to earn its authorized rate of

return. Therefore, the WNA provides the Company with a level of earnings protection when weather is significantly warmer than normal and provides its customers with price protection when the weather is significantly colder than normal. The WNA mechanism provides for a weather band of 3% above and below the 30-year average, whereby the Company would bill its customers for the lost margin (excluding gas costs) for the impact of weather that was more than 3% warmer than normal or refund customers the excess margin earned for weather that was more than 3% colder than normal. The annual WNA period extends from April to March. For the most recently completed WNA period ending in March 2012, weather was approximately 22% warmer than the 30-year normal with 883 fewer heating degree days (an industry measure by which the average daily temperature falls below 65 degrees Fahrenheit) compared to normal. As a result, the Company recorded approximately $1,747,000 in additional revenues to reflect the impact of the WNA in 2012 for the difference in margin not realized for warmer weather between 3% and 22% of the 30-year average. The Company did not record any WNA revenues during the prior WNA period in 2011 as total heating degree days were within the 3% weather band.

The Company also has an approved rate structure in place that mitigates the impact of financing costs of its natural gas inventory. Under this rate structure, Roanoke Gas recognizes revenue for the financing costs, or carrying costs , of its investment in natural gas inventory. The

carrying cost revenue factor applied to inventory is based on the Company s weighted-average cost of capital including interest rates on short-term and long-term debt and the Company s authorized return on equity. During times of rising gas costs and rising inventory levels, the Company recognizes revenues to offset higher financing costs associated with higher inventory balances. Conversely, during times of decreasing gas costs and lower inventory balances, the Company recognizes less carrying cost revenue as financing costs are lower. As a result of the lower commodity price of natural gas during the summer storage injection period, the average price of gas in storage during fiscal 2012 has declined 16% from last year s levels from $5.16 to $4.36 per decatherm. Correspondingly, carrying cost revenues declined by $159,000 from $1,396,000 in fiscal 2011 to $1,237,000 in fiscal 2012. Carrying cost revenues are expected to continue to trend lower during the next fiscal year.

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

Due to its strong cash position related to lower gas costs and other factors, the Company has not accessed its line-of-credit facility since early 2009 to finance its natural gas inventory.

The economic environment has a direct correlation with business and industrial production, customer growth and natural gas utilization. The economic downturn that began in 2008 appears to have stabilized with some

improvement in natural gas deliveries to industrial customers. Although certain customers are expected to limit their production activities in the coming year, the interruptible and transportation sales for 2011 and 2012 have returned to pre 2008 levels. Nevertheless, economic uncertainty continues and industrial activity could be impacted if the economy slows. Residential construction and housing starts continue to remain well below historical levels, thereby limiting customer growth opportunities.

RESULTS OF OPERATIONS

Fiscal Year 2012 Compared with Fiscal Year 2011

The tables below reflect operating revenues, volume activity and heating degree days.

OPERATING REVENUES

YEAR ENDED SEPTEMBER 30,	2012	2011	(DECREASE)	PERCENTAGE
GAS UTILITIES	**$ 57,657,940**	$ 69,483,620	$ (11,825,680)	-17%
OTHER	**1,141,747**	1,315,251	(173,504)	-13%
TOTAL OPERATING REVENUES	**$ 58,799,687**	$ 70,798,871	$ (11,999,184)	-17%

DELIVERED VOLUMES

YEAR ENDED SEPTEMBER 30,	2012	2011	INCREASE/ (DECREASE)	PERCENTAGE
REGULATED NATURAL GAS (DTH)				
RESIDENTIAL AND COMMERCIAL	**5,335,836**	6,582,487	(1,246,651)	-19%
TRANSPORTATION AND INTERRUPTIBLE	**2,981,660**	2,962,111	19,549	1%
TOTAL DELIVERED VOLUMES	**8,317,496**	9,544,598	(1,227,102)	-13%
HEATING DEGREE DAYS (UNOFFICIAL)	**3,189**	4,091	(902)	-22%

Total gas utility operating revenues for the year ended September 30, 2012 (fiscal 2012) decreased by 17% from the year ended September 30, 2011 (fiscal 2011) as total delivered volumes decreased by 13% from fiscal 2011. The decrease in gas revenues is due to significantly reduced natural gas sales due to a much warmer winter heating season combined with a continued downward trend in gas costs. Residential and commercial volumes declined by 19% compared to fiscal 2011 as total heating degree days during the period fell by 22%. A majority of residential and commercial sales volumes are dependent on weather and the significantly warmer winter resulted in a decrease

in usage. Transportation and interruptible volumes were nearly unchanged with a small increase of 1% with volumes returning to the pre 2008 levels. Natural gas commodity prices were approximately $3 a decatherm as of the end of September 2012 and were below $3 a decatherm for much of calendar 2012. For the year, the average commodity price per unit cost of natural gas reflected in cost of sales decreased by 22% compared to last year while the average total price per unit (including pipeline demand fees) decreased by 11%. Other revenues declined by 13% due to the decline in the level of certain contract services from last year.

The table below reflects gross margin.

GROSS MARGIN

YEAR ENDED SEPTEMBER 30,	2012	2011	(DECREASE)	PERCENTAGE
GAS UTILITY	**$ 26,379,767**	$ 26,667,821	$ (288,054)	-1%
OTHER	**553,330**	601,745	(48,415)	-8%
TOTAL GROSS MARGIN	**$ 26,933,097**	$ 27,269,566	$ (336,469)	-1%

Regulated natural gas margins from utility operations decreased 1% from the same period last year primarily as a result of significantly less total natural gas deliveries. Much of the margin lost due to the reduction in volumes delivered was recovered through the triggering of the WNA mechanism during the period. The Company recorded approximately $1,747,000 in additional revenues during the period to mitigate the shortfall in volumetric sales activity attributable to the warmer winter season. The Company also implemented a non-gas base rate increase designed to provide approximately $235,000 in additional annual revenues based on normal weather. The rate increase in non-gas billing rates accounted for approximately $200,000 in higher margins with approximately $90,000 attributable to customer base charges, a flat monthly fee billed to each natural gas customer, with the remaining balance related to volumetric sales. The remaining increase in customer base charges was primarily attributable to a higher number of billed meter accounts related to the conversion of six apartment complexes from a single master meter for each building to individual meters that occurred during fiscal 2011. Carrying cost revenues continued to decline with a $159,000 reduction due to lower average price of gas in storage combined with lower inventory balances as discussed above.

Other margins, consisting of non-utility related services, decreased by $48,415 due to a reduction in the level of certain contract services. Some of these non-utility services are subject to annual or semi-annual contract renewals. The Company has been able to renew these contracts; however, the demand for some services has declined. If the Company is unable to continue renewing or extending the largest contracts, margins from other revenues would be significantly impacted. The Company intends to continue to pursue these contracts where profitable; however, continuation in future periods is uncertain.

The changes in the components of the gas utility margin are summarized below:

NET UTILITY MARGIN DECREASE

CUSTOMER BASE CHARGE	$ 178,106
VOLUMETRIC	(2,014,190)
WNA	1,747,150
CARRYING COST	(159,164)
OTHER	(39,956)
TOTAL	$ (288,054)

OPERATIONS AND MAINTENANCE EXPENSE Operations and maintenance expenses decreased by $114,288, or 1%, in fiscal 2012 compared with fiscal 2011 primarily due to greater capitalization of Company labor and overheads on related construction projects and lower bad debt expense more than offsetting higher employee benefit costs. The Company increased activity under its pipeline renewal program resulting in total capital expenditures rising by more than $1 million, or 14%, over last year. As a result of higher capital spending and increased employee costs, the Company capitalized approximately $385,000 more in related overheads. Employee benefit costs increased by approximately $294,000, which contributed to the increase in capitalized overheads. The major components of the higher employee benefit costs related to increases in health insurance premiums and higher pension and post-retirement medical plan costs attributable to a decline in the discount rate used to measure the benefit liabilities and the

underperformance of the plan assets in the prior year. Both components were used in determining fiscal 2012 expense. The Company also realized a $55,000 reduction in bad debt expense. The lower bad debt expense was primarily attributable to significantly reduced natural gas deliveries and lower natural gas prices contributing to lower customer billings and reduced delinquencies. The remaining difference in operation and maintenance expenses primarily resulted from a $62,000 increase in corporate insurance premiums and a variety of other minor expense variances.

GENERAL TAXES General taxes increased $75,945, or 6%, primarily due to higher property taxes associated with increases in utility property partially offset by greater capitalization of payroll taxes.

DEPRECIATION Depreciation expense increased by $228,385, or 6%, corresponding to the increase in utility plant investment as part of the ongoing pipeline renewal program.

OTHER INCOME (EXPENSE) This line item moved from a net other income to a net other expense primarily due to reduction in investment earnings related to lower interest rates.

INTEREST EXPENSE Total interest expense for fiscal 2012 remained virtually unchanged from fiscal 2011 as total debt remained consistent and the Company did not access its line-of-credit facility during 2012 or 2011.

INCOME TAXES Income tax expense decreased by $208,162, or 7%, from fiscal 2011 corresponding to a comparable decrease in pre-tax earnings. The effective tax rate for fiscal 2012 and 2011 was 38.0 %.

NET INCOME AND DIVIDENDS Net income for fiscal 2012 was $4,296,745 compared to $4,653,473 for fiscal 2011. Basic and diluted earnings per share were $0.92 in fiscal 2012 compared to $1.01 in fiscal 2011. Dividends declared per share of common stock were $0.70 in fiscal 2012 and $0.68 in fiscal 2011.

Fiscal Year 2011 Compared with Fiscal Year 2010

The tables below reflect operating revenues, volume activity and heating degree days.

OPERATING REVENUES

YEAR ENDED SEPTEMBER 30,	2011	2010	(DECREASE)	PERCENTAGE
GAS UTILITIES	$ 69,483,620	$ 72,426,658	$ (2,943,038)	-4%
OTHER	1,315,251	1,397,256	(82,005)	-6%
TOTAL OPERATING REVENUES	$ 70,798,871	$ 73,823,914	$ (3,025,043)	-4%

DELIVERED VOLUMES

YEAR ENDED SEPTEMBER 30,	2011	2010	INCREASE/ (DECREASE)	PERCENTAGE
REGULATED NATURAL GAS (DTH)				
RESIDENTIAL AND COMMERCIAL	6,582,487	6,623,331	(40,844)	-1%
TRANSPORTATION AND INTERRUPTIBLE	2,962,111	2,690,820	271,291	10%
TOTAL DELIVERED VOLUMES	9,544,598	9,314,151	230,447	2%
HEATING DEGREE DAYS (UNOFFICIAL)	4,091	4,047	44	1%

Total gas utility operating revenues for the year ended September 30, 2011 (fiscal 2011) decreased by 4% from the year ended September 30, 2010 (fiscal 2010) even though total delivered volumes increased by 2% over fiscal 2010. The decrease in gas revenues was due to the continued downward trend in gas costs. Natural gas commodity prices were approximately $4 a decatherm as of the end of September 2011. For the year, the average per unit cost of natural gas, including pipeline demand costs, reflected in cost of sales decreased by 10% compared to the prior year. Residential and commercial volumes declined by 1% from fiscal 2010 even though total heating degree days increased by 1%. The decline in residential

and commercial volumes resulted from a large commercial customer switching to firm transportation service at the beginning of the year combined with the continuing slow, steady decline in residential usage per customer as a result of the installation of more energy efficient equipment and better insulation of homes. Transportation and interruptible volumes increased by 10% mainly due to additional consumption with the balance of the increase attributed to volumes associated with the previously discussed commercial customer switching to firm transportation service. Other revenues declined by 6% due to the decline in certain contract services from the prior year s levels.

GROSS MARGIN

YEAR ENDED SEPTEMBER 30,	2011	2010	INCREASE/ (DECREASE)	PERCENTAGE
GAS UTILITY	$ 26,667,821	$ 25,736,411	$ 931,410	4%
OTHER	601,745	703,862	(102,117)	-15%
TOTAL GROSS MARGIN	$ 27,269,566	$ 26,440,273	$ 829,293	3%

Gas utility margins increased by 4% primarily due to the implementation of a non-gas base rate increase and the completion of master meter conversion projects during the prior year, which combined to more than offset a reduction in carrying cost revenues. The increase in non-gas billing rates accounted for approximately $800,000 in higher margins with approximately $330,000 attributable to customer base charges with the balance related to volumetric sales. The remaining increase in customer base charges was primarily attributable to the conversion of six apartment complexes from a single master meter for each building to individual meters located at each apartment during 2010 and the higher customer fee associated with a customer switching to firm transportation service as discussed above. As a result of the master meter program, the Company added more than 1,000 meters subject to the monthly customer base charge during fiscal 2011. The balance of the increase in volumetric revenue was attributable to the increase in total delivered volumes. Carrying cost revenues declined by $151,000 due to lower average price of gas in storage combined with lower inventory balances.

Other margins, consisting of non-utility related services, decreased by $102,117 due to a reduction in certain contract services.

The changes in the components of the gas utility margin are summarized below:

NET UTILITY MARGIN INCREASE

CUSTOMER BASE CHARGE	$ 602,697
VOLUMETRIC	509,916
CARRYING COST	(150,667)
OTHER	(30,536)
TOTAL	$ 931,410

OPERATIONS AND MAINTENANCE EXPENSE Operations and maintenance expenses increased $308,502, or more than 2%, in fiscal 2011 compared with fiscal 2010 as a result of increases in employee benefit costs, labor and contracted services, partially offset by reductions in bad debt expense and a greater level of capitalized expenses. Employee benefit expenses increased $325,000 due to higher medical insurance

premiums and increases in pension and postretirement medical costs attributable to the amortization of larger actuarial losses in fiscal 2011. Labor and contracted services increased by $257,000 primarily due to brush removal along pipeline right-of-ways, a greater emphasis on the public awareness campaign to educate local residents and businesses regarding pipeline safety and other general cost increases. Bad debt expense declined by $72,000 as total utility revenues decreased by 4% associated with lower gas costs. Low natural gas prices and a continued emphasis on customer delinquencies contributed to the reduction in bad debt expense. The Company capitalized an additional $244,000 in overheads primarily due to increased capital expenditures and higher employee benefit costs. The remaining difference in operation and maintenance expenses resulted from a variety of other minor expense variances.

GENERAL TAXES General taxes were nearly unchanged as higher property taxes were offset by greater capitalization of payroll taxes.

DEPRECIATION Depreciation expense increased by $185,784, or 5%, due to a higher natural gas plant investment, primarily the result of completing several distribution pipeline renewal projects.

OTHER INCOME (EXPENSE) This line item moved from a net other expense to a net other income primarily due to greater investment earnings on higher available cash balances.

INTEREST EXPENSE Total interest expense for fiscal 2011 remained virtually unchanged from fiscal 2010 as total debt remained consistent and the Company did not access its line-of-credit facility during 2011 or 2010.

INCOME TAXES Income tax expense increased by $156,110, or 6%, from fiscal 2010 corresponding to a 5% increase in pre-tax earnings. The effective tax rate for fiscal 2011 was 38.0 % compared to 37.7% in fiscal 2010.

NET INCOME AND DIVIDENDS Net income for fiscal 2011 was $4,653,473 compared to $4,445,436 for fiscal 2010. Basic and diluted earnings per share were $1.01 in fiscal 2011 compared to $0.98 in fiscal 2010. Dividends declared per share of common stock were $0.68 in fiscal 2011 and $0.66 in fiscal 2010 as adjusted on a post stock split basis.

Asset Management

Roanoke Gas uses a third-party asset manager to manage its pipeline transportation, storage rights and gas supply inventories and deliveries. In return for being able to utilize the excess capacities of the transportation and storage rights, the third party pays Roanoke Gas a monthly utilization fee, which is used to reduce the cost of gas for customers. Under the provision of the asset management contract, the Company has an obligation to purchase its winter storage requirements during the spring and summer injection periods at the market price in place at the time of purchase. This commitment amounts to approximately 2,225,000 decatherms per year or approximately one-third of the Company s total annual purchases. In addition to the storage purchase requirements, the Company generally purchases its monthly supply requirements from the asset manager based on market price. The current agreement expires in October 2013.

Capital Resources and Liquidity

Due to the capital intensive nature of the utility business, as well as the related weather sensitivity, the Company s primary capital needs are for the funding of its continuing construction program, the seasonal funding of its natural gas inventories and accounts receivable and payment of dividends. To meet these needs, the Company

relies on its operating cash flows, line-of-credit agreement, long-term debt and capital raised through the Company s Dividend Reinvestment and Stock Purchase Plan (DRIP).

Cash and cash equivalents increased by $958,442 in fiscal 2012 compared to a $1,205,799 increase in fiscal 2011 and a $676,730 decrease in fiscal 2010. The following table summarizes the categories of sources and uses of cash:

CASH FLOW SUMMARY YEAR ENDED SEPTEMBER 30,	2012	2011	2010
PROVIDED BY OPERATING ACTIVITIES	**$ 11,783,041**	$ 10,683,344	$ 7,118,804
USED IN INVESTING ACTIVITIES	**(8,650,715)**	(7,589,102)	(5,963,321)
USED IN FINANCING ACTIVITIES	**(2,173,884)**	(1,888,443)	(1,832,213)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**$ 958,442**	$ 1,205,799	$ (676,730)

CASH FLOWS FROM OPERATING ACTIVITIES:

The seasonal nature of the natural gas business causes operating cash flows to fluctuate significantly during the year as well as from year to year. Factors, including weather, energy prices, natural gas storage levels and customer collections, all contribute to working capital levels and related cash flows. Generally, operating cash flows are positive during the second and third quarters as a combination of earnings, declining storage gas levels and collections on customer accounts all contribute to higher cash levels. During the first and fourth quarters, operating cash flows generally decrease due to the combination of increases in natural gas storage levels, rising customer receivable balances and construction activity.

Cash provided by operating activities was $11,783,041 in fiscal 2012, $10,683,344 in fiscal 2011 and $7,118,804 in fiscal 2010. Cash provided by operating activities continued to increase over the last three years due to net income, increasing depreciation, continued reduction in natural gas storage balances and continued tax benefits related to bonus depreciation. The commodity price of natural gas has continued its decline over the past few years. A mild winter combined with the increasing development of natural gas from shale have reduced gas prices, leading to lower natural gas storage balances as higher priced inventory is replaced with lower priced gas. The average price of gas in storage declined from $6.05 per decatherm at September 30, 2009 to $3.51 per

decatherm at September 30, 2012 on comparable volumes. This reduction in the cost of natural gas has generated more than $6.5 million in cash from operating activities over the last three years. In addition, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, which was signed into law in December 2010, extended the 50% bonus depreciation that expired December 31, 2009 and provided for 100% bonus depreciation for qualified investments from September 2010 through December 2011 and provided for 50% bonus depreciation through December 31, 2012. As a result of the Act, the Company s deferred income tax liability associated with its utility property increased by more than $2,200,000 in fiscal 2012 and $2,300,000 in fiscal 2011, thereby deferring payment of income taxes until future periods. The Company has almost $15,000,000 in deferred tax liabilities related to accelerated and bonus depreciation on its utility plant that will begin to reverse in future years resulting in additional cash outflows. The commodity price of natural gas appears to have reached its floor price thereby limiting any future potential positive cash impact. When natural gas prices begin to increase, additional cash will be required. The Company has used cash on operating activities as well. The Company has steadily reduced its over-collection of gas cost balance from $5,652,000 in 2009 to an under-collection of $687,000 at September 30, 2012, a net refunding of cash of $6,339,000 over the last three years.

CASH FLOWS USED IN INVESTING ACTIVITIES:

Investing activities are generally composed of expenditures under the Company s construction program, which involves a combination of replacing aging bare steel and cast iron pipe with new plastic or coated steel pipe, making improvements to the LNG plant and, to a lesser extent, expansion of its natural gas system to meet the demands of customer growth. The Company spent nearly $8,700,000 in capital expenditures in fiscal 2012 primarily related to its pipeline renewal program and various other system improvements. This compares to nearly $7,600,000 in fiscal 2011 and $6,000,000 in fiscal 2010. The Company renewed 15.8 miles of bare steel and cast iron natural gas distribution main and replaced 1,429 services in fiscal 2012. This compares to 8.9 miles of gas main and 720 services in fiscal 2011 and 6.4 miles of gas main and 420 services in fiscal 2010. RGC Resources is committed to the safe and reliable delivery of natural gas to its customers and, as a result, plans to commit the necessary resources to

its pipeline renewal program with an expectation to replace all remaining 44 miles of cast iron and bare steel pipe within the next six years. Depreciation provided 51% of the current year s capital expenditures compared to 55% for 2011 and 66% for 2010. With future capital expenditures expected to remain at or near these levels, the balance of the funding will come from net income, available cash, proceeds from DRIP and corporate borrowing activity.

CASH FLOWS USED IN FINANCING ACTIVITIES:

Financing activities generally consist of long-term and short-term borrowings and repayments, issuance of stock and the payment of dividends. As discussed above, the Company uses its line-of-credit arrangement to fund seasonal working capital needs as well as provide temporary financing for capital projects as needed. During fiscal 2012, 2011 and 2010, the Company did not access its line-of-credit due to cash generated from operating activities. Cash flows used in financing activities were $2,174,000 for fiscal 2012 compared to $1,888,000 in fiscal 2011 and $1,832,000 in fiscal 2010. The $2,174,000 net cash used in financing activities was composed of $3,226,000 from dividends paid net of approximately $774,000 of proceeds related to stock issuances and $278,000 related to payments received on two notes receivable. Subsequent to September 30, 2012, the $952,000 balance on the note with ANGD, LLC, originally due on November 2, 2012, was extended for one year under the same terms as previously in place.

On March 30, 2012, the Company entered into a new line-of-credit agreement. This new agreement maintains the same terms and rates as provided for under the expired agreement. The interest rate is based on 30-day LIBOR plus 100 basis points and includes an availability fee of 15 basis points applied to the difference between the face amount of the note and the average outstanding balance during the period. The Company maintained the multi-tiered borrowing limits to accommodate seasonal borrowing demands and minimize overall borrowing costs, with available limits ranging from $1,000,000 to $5,000,000 during the term of the agreement. The line-of-credit agreement will expire March 31, 2013, unless extended. The Company anticipates being able to extend or replace the line-of-credit upon expiration; however, there is no guarantee that the line-of-credit will be extended or replaced under the same or equivalent terms currently in place.

Also on March 30, 2012, the Company executed an unsecured term note in the amount of $15,000,000. This term note extends the maturity date of the original promissory note dated November 28, 2005 and subsequent modification dated October 20, 2010. The term note, which has a maturity date of March 31, 2013, retains all other terms and conditions provided for in the original promissory note. The Company anticipates being able to renew this note on comparable terms as currently in place until such time the note co-terminates with the corresponding interest rate swap on November 30, 2015.

On October 29, 2012, the Board of Directors of RGC Resources declared a special one-time dividend of $1.00 per share on the Company s outstanding common stock payable on December 17, 2012, to shareholders of record on November 30, 2012. The intent of the dividend is to distribute a portion of equity capital previously deployed to finance higher natural gas inventory balances and allow for the realignment of the Company s capital structure to be more in line with regulatory expectations. The Company s consolidated capitalization, including the note payable, was 64% equity and 36% debt at September 30, 2012 and 2011. The application of the special dividend to the September 30, 2012 balances would result in a capitalization of 62% equity and 38% debt.

As mentioned above, the Company has not accessed its line-of-credit facility during the last three years and has been able to finance operations with its operating cash flow. The key factor behind the improved cash position of the Company is the reduction in the commodity price of natural gas to approximately $3 per decatherm at September 30, 2012. As a result of the lower commodity price of gas, the average balance of gas in storage declined from $18,300,000 from its peak in fiscal 2008 to $8,800,000 during fiscal 2012. Likewise, accounts receivable experienced a similar decline in average balances during the same period. If natural gas prices remain at the levels experienced in fiscal 2012, the Company anticipates that it will be able to finance its operations, including its pipeline renewal program, over the next few years with its operating cash flows and line-of-credit.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no off-balance sheet arrangements as defined in Regulation S-K, Item 303(a)(4)(ii).

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has incurred various contractual obligations and commitments in the normal course of business. As of

September 30, 2012, the estimated recorded and unrecorded obligations are as follows:

	PAYMENTS DUE BY PERIOD				
	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS	TOTAL
RECORDED CONTRACTUAL OBLIGATIONS:					
LONG TERM DEBT(1)	$	$ 1,600,000	$ 8,200,000	$ 3,200,000	$ 13,000,000
SHORT TERM DEBT(2)	15,000,000				15,000,000
TOTAL	**$ 15,000,000**	**$ 1,600,000**	**$ 8,200,000**	**$ 3,200,000**	**$ 28,000,000**

(1) SEE NOTE 4 TO THE CONSOLIDATED FINANCIAL STATEMENTS
(2) SEE NOTE 3 TO THE CONSOLIDATED FINANCIAL STATEMENTS

	PAYMENTS DUE BY PERIOD				
	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS	TOTAL
UNRECORDED CONTRACTUAL OBLIGATIONS, **NOT** REFLECTED IN CONSOLIDATED BALANCE SHEETS PER ACCORDANCE WITH U.S. GAAP:					
PIPELINE AND STORAGE CAPACITY(3)	$ 11,439,832	$ 15,189,688	$ 5,862,245	$ 3,984,337	$ 36,476,102
GAS SUPPLY(4)					
INTEREST ON SHORT-TERM DEBT(5)	2,312,500				2,312,500
INTEREST ON LONG-TERM DEBT(6)	902,300	1,702,467	701,904	163,414	3,470,085
PENSION PLAN FUNDING(7)	1,100,000	2,187,000	2,090,000		5,377,000
OTHER OBLIGATIONS(8)	206,030	195,842	36,962	1,359	440,193
TOTAL	**$ 15,960,662**	**$ 19,274,997**	**$ 8,691,111**	**$ 4,149,110**	**$ 48,075,880**

(3) RECOVERABLE THROUGH PGA PROCESS
(4) VOLUMETRIC OBLIGATION FOR THE PURCHASE OF CONTRACTED DECATHERMS OF NATURAL GAS AT MARKET PRICES IN EFFECT AT THE TIME OF PURCHASE. SEE NOTE 9 TO THE CONSOLIDATED FINANCIAL STATEMENTS.
(5) INCLUDES PAYMENTS UNDER THE SWAP AGREEMENT INCLUDING THE ESTIMATED SETTLEMENT OF THE SWAP ASSUMING THE CORRESPONDING NOTE WAS NOT EXTENDED. THE COMPANY EXPECTS TO EXTEND THIS NOTE UNTIL SUCH TIME AS THE SWAP MATURES. SEE NOTE 3 TO THE CONSOLIDATED FINANCIAL STATEMENTS.
(6) INCLUDES PAYMENTS UNDER THE SWAP AGREEMENT. SEE NOTE 4 TO THE CONSOLIDATED FINANCIAL STATEMENTS.
(7) ESTIMATED FUNDING BEYOND FIVE YEARS IS NOT AVAILABLE. SEE NOTE 6 TO THE CONSOLIDATED FINANCIAL STATEMENTS.
(8) VARIOUS LEASE, MAINTENANCE, EQUIPMENT AND SERVICE CONTRACTS.

REGULATORY AFFAIRS

On November 1, 2011, the Company placed into effect new base rates, subject to refund, that would provide approximately $1,100,000 in additional non-gas revenues on an annual basis. On May 2, 2012, the SCC issued a final order granting a rate award of $235,000. In June 2012, the Company completed its refund of excess non-gas revenues collected for rates placed into effect on November 1, 2011 and the final rates approved in the final order.

On September 14, 2012, the Company filed a request for an expedited increase in rates with the SCC. The request was for an increase of approximately $1,840,000 in annual non-gas revenues. As provided for under this expedited rate request, the Company was able to place the increased rates into effect for service rendered on and after November 1, 2012, subject to refund pending a final order by the SCC. The public hearing on the request for this rate increase is scheduled for March 26, 2013, with a final order expected after that date.

On March 15, 2012, the Company filed an application for the approval of a SAVE (Steps to Advance Virginia s Energy) Plan and Rider. The SAVE plan is designed to facilitate the accelerated replacement of aging natural gas infrastructure assets by providing the Company with a means to recover depreciation and related expenses associated with the replacement of bare steel and cast iron pipe as these projects are taking place. Without the SAVE rider, the Company would not be able to recover the related depreciation and expenses and return on rate base until a formal application for an increase in non-gas base rates is filed following the replacement. The SAVE Plan provides the Company with a more timely mechanism for recovering the cost of its renewal program. On July 25, 2012, the SCC approved the SAVE Plan and Rider with an initial effective date of January 1, 2013.

During 2011, the Company completed its Distribution Integrity Management Plan (DIMP) as required by federal regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). Under these regulations, distribution operators are required to develop and implement a written DIMP plan that includes the following elements: (i) an operator must demonstrate an understanding of the gas distribution system, (ii) an

operator must define the potential threats to the gas distribution pipeline and determine the relative probability of each threat (a risk based approach), (iii) an operator must determine and implement measures designed to reduce the risks of failure of its gas distribution system, (iv) an operator must develop and monitor performance measures to evaluate the effectiveness of its plan, and (v) an operator must continually re-evaluate threats and risks on its entire system and update its plan as necessary.

The Company had been proactive in the area of pipeline safety well before implementation of the DIMP regulations. Over the past 20 years, the Company has replaced much of its cast iron and bare steel pipe. As this pipe has been underground for well over 60 years, the leak potential from such pipe is much higher than the plastic or coated steel pipe currently being installed. The Company prioritized its replacement program using a risk based evaluation that included leak history, population density and other factors. During this time period, the Company has replaced all but approximately 44 miles of bare steel and cast iron distribution main. The Company expects to replace the remaining pipe within the next six years.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

The Company considers an estimate to be critical if it is material to the financial statements and requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. The Company considers the following accounting policies and estimates to be critical.

REGULATORY ACCOUNTING The Company s regulated operations follow the accounting and reporting requirements of FASB ASC No. 980, *Regulated Operations*. The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities).

If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the Company would remove the applicable regulatory assets or liabilities from the balance sheet and include them in the consolidated statement of income and comprehensive income for the period in which the discontinuance occurred.

REVENUE RECOGNITION Regulated utility sales and transportation revenues are based upon rates approved by the SCC. The non-gas cost component of rates may not be changed without a formal rate increase application and corresponding authorization by the SCC in the form of a Commission order; however, the gas cost component of rates may be adjusted quarterly through the purchased gas adjustment (PGA) mechanism with administrative approval from the SCC. When the Company files a request for a non-gas rate increase, the SCC may allow the Company to place such rates into effect subject to refund pending a final order. Under these circumstances, the Company estimates the amount of increase it anticipates will be approved based on the best available information.

The Company bills its regulated natural gas customers on a monthly cycle. The billing cycle for most customers does not coincide with the accounting periods used for financial reporting. The Company accrues estimated revenue for natural gas delivered to customers but not yet billed during the accounting period based on weather during the period and current and historical data. The financial statements include unbilled revenue of $951,301 and $1,088,611 as of September 30, 2012 and 2011.

ALLOWANCE FOR DOUBTFUL ACCOUNTS The Company evaluates the collectibility of its accounts receivable balances based upon a variety of factors including loss history, level of delinquent account balances, collections on previously written off accounts and general economic climate.

PENSION AND POSTRETIREMENT BENEFITS The Company offers a defined benefit pension plan (pension plan) and a postretirement medical and life insurance plan (postretirement plan) to eligible employees. The expenses and liabilities associated with these plans, as disclosed in Note 6 to the consolidated financial statements, are based on numerous assumptions and factors, including provisions of the plans, employee demographics, contributions made to the plan, return on plan assets and various actuarial calculations, assumptions and accounting requirements. In regard to the pension plan, specific factors include assumptions regarding the discount rate used in determining future benefit obligations, expected long-term rate of return on plan assets, compensation increases and life expectancies. Similarly, the postretirement medical plan also requires the estimation of many of the same factors as the pension plan in addition to assumptions regarding the rate of medical inflation and Medicare availability. Actual results may differ materially from the results expected from the actuarial assumptions due to changing economic conditions, volatility in interest rates and changes in life expectancy. Such differences may result in a material impact on the amount of expense recorded in future periods or the value of the obligations on the balance sheet.

In selecting the discount rate to be used in determining the benefit liability, the Company evaluated the IRS yield curves and the Citigroup yield curves which incorporate the rates of return on high-quality, fixed-income investments that corresponded to the length and timing of benefit streams expected under both the pension plan and postretirement plan. The Company used a discount rate of 4.06% and 3.95% for valuing its pension benefit liability and postretirement plan liability at September 30, 2012, representing a decrease of 0.98% and 1.01% in the respective discount rates from the prior year. The decrease in the discount rates resulted in a significant increase in the benefit liability for both plans. The impact to each plan s funded status and related liability reflected on the Company s balance sheet was mitigated by strong returns