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 on the related pension and postretirement assets. Although total benefit obligations increased by nearly $6,000,000, the funded status of both plans only declined by $1,200,000. In the current interest rate environment, rates are expected to remain at unusually low levels, thereby limiting any near-term relief on the benefit obligation. The Company also used an asset/liability model to evaluate the probability of meeting the returns on its targeted investment allocation model. The investment policy as of the measurement date in September reflected a targeted allocation of 60% equity and 40% fixed income for an assumed long-term rate of return of 7.25% on the pension plan and a targeted allocation of 50% equity and 50% fixed income for an assumed long-term rate of return of 5.11% (net of income taxes) for the postretirement plan.

In early July 2012, the President signed into law the Moving Ahead for Progress in the 21st Century Act (MAP-21), which provided funding relief for defined benefit pension plans. The requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and the Pension Protection Act of 2006 (PPA) subject defined benefit plans to minimum funding rules. As a result, when interest rates are low, pension plan liabilities increase thereby resulting in higher mandatory contributions to meet minimum funding obligations. The MAP-21 provides funding relief by allowing pension plans to adjust the interest rate used in determining funding requirements so that they are within 10% of the average of interest rates for the 25-year period preceding the current year for funding calculations for 2012 to 30% for funding periods beginning in 2016. MAP-21 also provides for increases in the PBGC (Pension Benefit Guaranty Corporation) premiums paid by sponsors of pension plans to protect

participants in the event of default by the employer. Although MAP-21 allows the Company some short-term funding relief, management expects to continue to fund its pension plan at the greater of any minimum pension contribution requirement or its expense level for subsequent years to improve both plans funded positions. As a result, the Company expects to contribute approximately $1,100,000 to its pension plan and $850,000 to its postretirement plan in fiscal 2013. The Company will continue to evaluate its benefit plan funding levels in light of funding requirements and ongoing investment returns and make adjustments, as necessary, to avoid benefit restrictions.

As the end of calendar 2012 approaches, much discussion has occurred as to how to address the pending fiscal cliff . If Congress and the President are unable to take action to address this issue, then mandatory federal budget cuts and tax increases will be enacted automatically. One item being discussed relates to the potential deferral age for Medicare eligibility. Currently, Medicare eligibility begins at age 65. If, in an effort to reduce Medicare costs, legislation is passed to defer the eligibility age beyond age 65, the Company s postretirement plan obligation as well as its future expense could increase as eligible participants would continue to be covered under the Company s group health insurance plan until such time as they would be eligible for Medicare. The Company is unable to estimate the likelihood of passage of such potential legislation at this time.

The following schedules reflect the sensitivity of pension costs and postretirement benefit costs to changes in certain actuarial assumptions, assuming that the other components of the calculation remain constant.

ACTUARIAL ASSUMPTION	CHANGE IN ASSUMPTION	INCREASE IN PENSION COST	INCREASE IN PROJECTED BENEFIT OBLIGATION
DISCOUNT RATE	-0.25%	$ 108,000	$ 1,031,000
RATE OF RETURN ON PLAN ASSETS	-0.25%	41,000	N/A
RATE OF INCREASE IN COMPENSATION	0.25%	63,000	351,000

ACTUARIAL ASSUMPTION	CHANGE IN ASSUMPTION	INCREASE IN POSTRETIREMENT BENEFIT COST	INCREASE IN ACCUMULATED POSTRETIREMENT BENEFIT OBLIGATION
DISCOUNT RATE	-0.25%	$ 39,000	$ 534,000
RATE OF RETURN ON PLAN ASSETS	-0.25%	22,000	N/A
HEALTH CARE COST TREND RATE	0.25%	78,000	556,000

DERIVATIVES The Company may hedge certain risks incurred in its operation through the use of derivative instruments. The Company applies the requirements of FASB ASC No. 815, *Derivatives and Hedging*, which requires the recognition of derivative instruments as assets or liabilities in the Company s balance sheet at fair value. In most instances, fair value is based upon quoted futures

prices for natural gas commodities and interest rate futures for interest rate swaps. Changes in the commodity and futures markets will impact the estimates of fair value in the future. Furthermore, the actual market value at the point of realization of the derivative may be significantly different from the values used in determining fair value in prior financial statements.

Market Price and Dividend Information

RGC Resources common stock is listed on the Nasdaq National Market under the trading symbol RGCO. Payment of dividends is within the discretion of the Board of Directors and will depend on, among other factors, earnings, capital requirements, and the operating and financial condition of

the Company. The Company s long-term indebtedness contains restrictions on dividends based on cumulative net earnings and dividends previously paid. The amounts presented below have been adjusted to reflect the stock split effected in the form of a 100% stock dividend in 2011:

FISCAL YEAR ENDED SEPTEMBER 30,	RANGE OF BID PRICES HIGH	LOW	CASH DIVIDENDS DECLARED
2012			
FIRST QUARTER	**$ 19.19**	**$ 17.14**	**$ 0.175**
SECOND QUARTER	**19.52**	**17.03**	**0.175**
THIRD QUARTER	**18.88**	**16.99**	**0.175**
FOURTH QUARTER	**18.81**	**17.49**	**0.175**
2011			
FIRST QUARTER	$ 16.77	$ 14.95	$ 0.170
SECOND QUARTER	17.82	14.64	0.170
THIRD QUARTER	17.23	15.54	0.170
FOURTH QUARTER	19.50	15.01	0.170

CAPITALIZATION STATISTICS

FISCAL YEAR ENDED SEPTEMBER 30,	2012	2011	2010	2009	2008
COMMON STOCK					
SHARES ISSUED	**4,670,567**	4,624,682	4,548,864	4,477,974	4,418,942
CONTINUING OPERATIONS:					
BASIC EARNINGS PER SHARE	**$ 0.92**	$ 1.01	$ 0.98	$ 1.09	$ 0.97
DILUTED EARNINGS PER SHARE	**$ 0.92**	$ 1.01	$ 0.98	$ 1.09	$ 0.96
DISCONTINUED OPERATIONS:					
BASIC EARNINGS PER SHARE	**$ 0.00**	$ 0.00	$ 0.00	$ 0.00	$ (0.01)
DILUTED EARNINGS PER SHARE	**$ 0.00**	$ 0.00	$ 0.00	$ 0.00	$ (0.01)
DIVIDENDS PAID PER SHARE (CASH)	**$ 0.700**	$ 0.680	$ 0.660	$ 0.640	$ 0.625
DIVIDENDS PAID OUT RATIO	**76.1%**	67.3%	67.3%	58.7%	65.1%
CAPITALIZATION RATIOS					
LONG-TERM DEBT, INCLUDING CURRENT MATURITIES	**20.4%**	36.5%	37.7%	38.5%	34.5%
COMMON STOCK AND SURPLUS	**79.6%**	63.5%	62.3%	61.5%	65.5%
TOTAL	**100.0%**	100.0%	100.0%	100.0%	100.0%
LONG-TERM DEBT, INCLUDING CURRENT MATURITIES	**$ 13,000,000**	$ 28,000,000	$ 28,000,000	$ 28,000,000	$ 23,000,000
COMMON STOCK AND SURPLUS	**50,682,930**	48,785,778	46,309,747	44,799,871	43,723,058
TOTAL CAPITALIZATION PLUS CURRENT MATURITIES	**$ 63,682,930**	$ 76,785,778	$ 74,309,747	$ 72,799,871	$ 66,723,058

Summary of Gas Sales and Statistics

YEARS ENDED SEPTEMBER 30,	2012	2011	2010	2009	2008
REVENUES					
RESIDENTIAL SALES	**$ 32,784,791**	$ 40,051,923	$ 42,277,903	$ 46,215,441	$ 51,634,728
COMMERCIAL SALES	**19,164,789**	23,463,529	25,166,672	28,936,307	35,496,410
INTERRUPTIBLE SALES	**1,397,353**	1,572,270	573,946	609,698	1,462,174
TRANSPORTATION GAS SALES	**2,957,344**	2,843,115	2,674,151	2,506,958	2,428,656
BACKUP SERVICES				300	3,600
INVENTORY CARRYING COST REVENUES	**1,236,713**	1,395,877	1,546,544	2,327,508	2,350,968
LATE PAYMENT CHARGES	**37,519**	44,252	63,949	56,718	55,410
MISCELLANEOUS GAS UTILITY REVENUE	**79,431**	112,654	123,493	133,298	174,647
OTHER	**1,141,747**	1,315,251	1,397,256	1,398,245	1,030,233
TOTAL	**$ 58,799,687**	$ 70,798,871	$ 73,823,914	$ 82,184,473	$ 94,636,826
NET INCOME					
CONTINUING OPERATIONS	**$ 4,296,745**	$ 4,653,473	$ 4,445,436	$ 4,869,010	$ 4,257,824
DISCONTINUED OPERATIONS					(36,690)
NET INCOME	**$ 4,296,745**	$ 4,653,473	$ 4,445,436	$ 4,869,010	$ 4,221,134
DTH DELIVERED:					
RESIDENTIAL	**3,036,076**	3,866,489	3,910,639	3,866,956	3,557,249
COMMERCIAL	**2,299,760**	2,715,998	2,712,692	2,830,782	2,785,701
INTERRUPTIBLE	**286,326**	263,851	79,858	75,061	128,875
TRANSPORTATION GAS	**2,695,334**	2,698,260	2,610,962	2,487,670	2,779,429
TOTAL	**8,317,496**	9,544,598	9,314,151	9,260,469	9,251,254
HEATING DEGREE DAYS	**3,189**	**4,091**	**4,047**	**3,914**	**3,624**
NUMBER OF CUSTOMERS					
NATURAL GAS					
RESIDENTIAL	**52,836**	52,579	51,922	51,069	50,630
COMMERCIAL	**5,072**	5,073	5,020	5,018	5,026
INTERRUPTIBLE AND TRANSPORTATION	**33**	32	33	32	33
TOTAL	**57,941**	57,684	56,975	56,119	55,689
GAS ACCOUNT (DTH)					
NATURAL GAS AVAILABLE	**8,521,983**	9,772,756	9,561,029	9,549,231	9,528,890
NATURAL GAS DELIVERIES	**8,317,496**	9,544,598	9,314,151	9,260,469	9,251,254
STORAGE - LNG	**111,735**	114,670	136,972	124,925	122,874
COMPANY USE AND MISCELLANEOUS	**41,620**	42,147	47,759	39,697	45,180
SYSTEM LOSS	**51,132**	71,341	62,147	124,140	109,582
TOTAL GAS AVAILABLE	**8,521,983**	9,772,756	9,561,029	9,549,231	9,528,890
TOTAL ASSETS	**$ 129,756,338**	**$ 125,549,049**	**$ 120,683,316**	**$ 118,801,892**	**$ 118,127,714**
LONG-TERM OBLIGATIONS	**$ 13,000,000**	**$ 13,000,000**	**$ 28,000,000**	**$ 28,000,000**	**$ 23,000,000**

RGC Resources, Inc. and Subsidiaries

Consolidated Financial Statements

for the Years Ended September 30, 2012, 2011

and 2010, and Report of Independent

Registered Public Accounting Firm

RGC RESOURCES, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RGC Resources, Inc.

Roanoke, Virginia

We have audited the accompanying consolidated balance sheets of RGC Resources, Inc. and Subsidiaries (the Company) as of September 30, 2012 and 2011, and the related consolidated statements of income, comprehensive income, stockholders equity, and cash flows for each of the years in the three-year period ended September 30, 2012. RGC Resources, Inc. s management is responsible for these financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, the financial statements referred to above present fairly, in all material respects, the financial position of RGC Resources, Inc. and Subsidiaries as of September 30, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended September 30, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), RGC Resources, Inc. and Subsidiaries internal control over financial reporting as of September 30, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated November 2, 2012 expressed an unqualified opinion.

CERTIFIED PUBLIC ACCOUNTANTS

100 Arbor Drive

Christiansburg, Virginia

November 2, 2012

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2012 AND 2011

	2012	2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8,909,871	$ 7,951,429
Accounts receivable, less allowance for doubtful accounts of $65,219 in 2012 and $66,058 in 2011	3,617,925	3,437,904
Notes receivable	1,142,770	277,770
Materials and supplies	613,548	583,157
Gas in storage	9,466,095	12,890,934
Prepaid income taxes	2,072,687	1,741,349
Deferred income taxes	2,371,609	2,870,843
Under-recovery of gas costs	687,194	
Other	1,365,615	1,250,859
Total current assets	30,247,314	31,004,245
UTILITY PROPERTY:		
In service	135,912,571	128,709,183
Accumulated depreciation and amortization	(46,563,520)	(45,191,684)
In service, net	89,349,051	83,517,499
Construction work in progress	1,481,041	2,204,957
Utility plant, net	90,830,092	85,722,456
OTHER ASSETS:		
Notes receivable		1,142,770
Regulatory assets	8,542,048	7,547,729
Other	136,884	131,849
Total other assets	8,678,932	8,822,348
TOTAL ASSETS	$ 129,756,338	$ 125,549,049

(Continued)

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2012 AND 2011

	2012	2011
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$	$ 15,000,000
Note payable	15,000,000	
Dividends payable	817,462	786,270
Accounts payable	4,756,460	5,299,475
Customer credit balances	2,382,089	2,525,071
Customer deposits	1,567,501	1,607,844
Accrued expenses	2,102,165	2,141,132
Over-recovery of gas costs		355,476
Fair value of marked-to-market transactions	2,916,718	3,312,176
Total current liabilities	29,542,395	31,027,444
LONG-TERM DEBT	13,000,000	13,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	4,251,295	3,863,933
Regulatory cost of retirement obligations	7,828,157	7,596,678
Benefit plan liabilities	12,541,251	11,326,909
Deferred income taxes	11,898,178	9,927,135
Deferred investment tax credits	12,132	21,172
Total deferred credits and other liabilities	36,531,013	32,735,827
COMMITMENTS AND CONTINGENCIES (Note 9)		
CAPITALIZATION:		
Stockholders Equity:		
Common Stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 4,670,567 and 4,624,682 shares in 2012 and 2011, respectively	23,352,835	23,123,410
Preferred stock, no par; authorized 5,000,000 shares; no shares issued and outstanding in 2012 and 2011		
Capital in excess of par value	7,375,666	6,830,395
Retained earnings	23,904,514	22,865,311
Accumulated other comprehensive loss	(3,950,085)	(4,033,338)
Total stockholders equity	50,682,930	48,785,778
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 129,756,338	$ 125,549,049

(Concluded)

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED SEPTEMBER 30, 2012, 2011 AND 2010

	2012	**2011**	**2010**
OPERATING REVENUES:			
Gas utilities	$ 57,657,940	$ 69,483,620	$ 72,426,658
Other	1,141,747	1,315,251	1,397,256
Total operating revenues	58,799,687	70,798,871	73,823,914
COST OF SALES:			
Gas utilities	31,278,173	42,815,799	46,690,247
Other	588,417	713,506	693,394
Total cost of sales	31,866,590	43,529,305	47,383,641
GROSS MARGIN	26,933,097	27,269,566	26,440,273
OTHER OPERATING EXPENSES:			
Operations and maintenance	12,547,693	12,661,981	12,353,479
General taxes	1,366,680	1,290,735	1,286,593
Depreciation and amortization	4,232,189	4,003,804	3,818,020
Total other operating expenses	18,146,562	17,956,520	17,458,092
OPERATING INCOME	8,786,535	9,313,046	8,982,181
OTHER INCOME (EXPENSE), net	(19,956)	20,250	(10,453)
INTEREST EXPENSE	1,830,885	1,832,712	1,835,291
INCOME BEFORE INCOME TAXES	6,935,694	7,500,584	7,136,437
INCOME TAX EXPENSE	2,638,949	2,847,111	2,691,001
NET INCOME	$ 4,296,745	$ 4,653,473	$ 4,445,436
EARNINGS PER COMMON SHARE:			
Basic	$ 0.92	$ 1.01	$ 0.98
Diluted	$ 0.92	$ 1.01	$ 0.98
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	4,647,439	4,592,713	4,514,262
Diluted	4,650,949	4,600,792	4,528,160

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2012, 2011 AND 2010

	2012	2011	2010
NET INCOME	$ 4,296,745	$ 4,653,473	$ 4,445,436
Other comprehensive income, net of tax:			
Interest rate SWAPs	245,343	139,199	(673,438)
Defined benefit plans	(162,090)	(305,714)	(308,679)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	83,253	(166,515)	(982,117)
COMPREHENSIVE INCOME	$ 4,379,998	$ 4,486,958	$ 3,463,319

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2012, 2011 AND 2010

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Balance - September 30, 2009	$ 11,194,935	$ 16,607,897	$ 19,881,745	$ (2,884,706)	$ 44,799,871
Net income			4,445,436		4,445,436
Other comprehensive income				(982,117)	(982,117)
Tax benefits from stock option exercise		34,906			34,906
Cash dividends declared ($0.66 per share)			(2,985,441)		(2,985,441)
Issuance of common stock (70,890 shares)	177,225	819,867			997,092
Balance - September 30, 2010	$ 11,372,160	$ 17,462,670	$ 21,341,740	$ (3,866,823)	$ 46,309,747
Net income			4,653,473		4,653,473
Other comprehensive income				(166,515)	(166,515)
Tax benefits from stock option exercise		40,746			40,746
Cash dividends declared ($0.68 per share)			(3,129,902)		(3,129,902)
Stock split	11,560,575	(11,560,575)			
Issuance costs - stock split		(34,205)			(34,205)
Issuance of common stock (75,818 shares)	190,675	921,759			1,112,434
Balance - September 30, 2011	$ 23,123,410	$ 6,830,395	$ 22,865,311	$ (4,033,338)	$ 48,785,778
Net income			4,296,745		4,296,745
Other comprehensive income				83,253	83,253
Tax benefits from stock option exercise		34,818			34,818
Cash dividends declared ($0.70 per share)			(3,257,542)		(3,257,542)
Issuance of common stock (45,885 shares)	229,425	510,453			739,878
Balance - September 30, 2012	$ 23,352,835	$ 7,375,666	$ 23,904,514	$ (3,950,085)	$ 50,682,930

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2012, 2011 AND 2010

	2012	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 4,296,745	$ 4,653,473	$ 4,445,436
Adjustments to reconcile net income to net cash provided by operations:			
Depreciation and amortization	4,387,016	4,164,320	3,959,887
Cost of retirement of utility plant, net	(436,120)	(302,340)	(307,375)
Deferred taxes and investment tax credits	2,410,468	2,720,657	1,884,235
Other noncash items, net	35,865	(42,938)	95,658
Changes in assets and liabilities which provided (used) cash:			
Accounts receivable and customer deposits, net	(51,234)	(189,410)	320,981
Inventories and gas in storage	3,394,448	899,295	2,287,340
Over/under recovery of gas costs	(1,042,670)	(2,309,284)	(2,987,087)
Other assets	(418,598)	882,148	(640,846)
Accounts payable, customer credit balances and accrued expenses, net	(792,879)	207,423	(1,939,425)
Total adjustments	7,486,296	6,029,871	2,673,368
Net cash provided by operating activities	11,783,041	10,683,344	7,118,804
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for utility property	(8,683,658)	(7,589,386)	(5,973,586)
Proceeds from disposal of utility property	32,943	284	10,265
Net cash used in investing activities	(8,650,715)	(7,589,102)	(5,963,321)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds on collection of notes	277,770	87,000	87,000
Proceeds from issuance of stock	774,696	1,118,975	1,031,998
Cash dividends paid	(3,226,350)	(3,094,418)	(2,951,211)
Net cash used in financing activities	(2,173,884)	(1,888,443)	(1,832,213)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	958,442	1,205,799	(676,730)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	7,951,429	6,745,630	7,422,360
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 8,909,871	$ 7,951,429	$ 6,745,630
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid (refunded) during the year for:			
Interest	$ 1,783,918	$ 1,799,459	$ 1,807,863
Income taxes	525,000	(705,000)	1,329,000
Non-cash transactions:			

A note in the amount of $381,540 was received in 2011 to reimburse the Company for the relocation of a gas distribution line.

See notes to consolidated financial statements.

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2012, 2011 AND 2010

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation RGC Resources, Inc. is an energy services company engaged in the sale and distribution of natural gas. The consolidated financial statements include the accounts of RGC Resources, Inc. and its wholly owned subsidiaries (Resources or the Company); Roanoke Gas Company (Roanoke Gas); Diversified Energy Company; and RGC Ventures of Virginia, Inc., operating as Application Resources and The Utility Consultants. Roanoke Gas is a natural gas utility, which distributes and sells natural gas to approximately 57,900 residential, commercial and industrial customers within its service areas in Roanoke, Virginia and the surrounding localities. The Company s business is seasonal in nature and weather dependent as a majority of natural gas sales are for space heating during the winter season. Roanoke Gas is regulated by the Virginia State Corporation Commission (SCC or Virginia Commission). Application Resources provides information system services to software providers in the utility industry. The Utility Consultants provides regulatory consulting services to other utilities. Diversified Energy Company is currently inactive.

The Company follows accounting and reporting standards set by the Financial Accounting Standards Board (FASB) and the Securities and Exchange Commission (SEC).

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

Rate Regulated Basis of Accounting The Company s regulated operations follow the accounting and reporting requirements of FASB ASC No. 980, *Regulated Operations*. The economic effects of regulation can result in a regulated company deferring costs that have been or are expected to be recovered from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this situation occurs, costs are deferred as assets in the consolidated balance sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities). In the event the provisions of FASB ASC No. 980 no longer apply to any or all regulatory assets or liabilities, the Company would write off such amounts and include them in the consolidated statement of income and comprehensive income in the period for which FASB ASC No. 980 no longer applied.

Regulatory assets and liabilities included in the Company s consolidated balance sheets as of September 30, 2012 and 2011 are as follows:

	September 30 2012	2011
Regulatory Assets:		
Current Assets:		
Under-recovery of gas costs	$ 687,194	$
Other:		
Accrued pension and postretirement medical	706,470	661,376
Utility Property:		
In service:		
Other	11,945	11,945
Other Assets:		
Regulatory assets:		
Premium on early retirement of debt	96,193	126,570
Accrued pension and postretirement medical	8,433,855	7,421,159
Other	12,000	
Total regulatory assets	$ 9,947,657	$ 8,221,050
Regulatory Liabilities:		
Current Liabilities:		
Over-recovery of gas costs	$	$ 355,476
Deferred Credits and Other Liabilities:		
Asset retirement obligations	4,251,295	3,863,933
Regulatory cost of retirement obligations	7,828,157	7,596,678
Total regulatory liabilities	$ 12,079,452	$ 11,816,087

As of September 30, 2012, the Company had regulatory assets in the amount of $9,140,325 on which the Company did not earn a return during the recovery period. These assets pertain to the net funded position of the Company s benefit plans related to its regulated operations. As such, the amortization period is not specifically defined.

Utility Plant and Depreciation Utility plant is stated at original cost. The cost of additions to utility plant includes direct charges and overhead. The cost of depreciable property retired is charged to accumulated depreciation. The cost of asset removals, less salvage, is charged to regulatory cost of retirement obligations or asset retirement obligations as explained under Asset Retirement Obligations below. Maintenance, repairs, and minor renewals and betterments of property are charged to operations and maintenance.

Provisions for depreciation are computed principally at composite straight-line rates as determined by depreciation studies required to be performed on the regulated utility assets of Roanoke Gas Company every five years. The Company completed its most recent depreciation study in July 2009. The composite weighted-average depreciation rate under the current depreciation study was 3.34%, 3.34% and 3.32% for the fiscal years ended September 30, 2012, 2011 and 2010, respectively.

The composite rates are comprised of two components, one based on average service life and one based on cost of retirement. As a result, the Company accrues the estimated cost of retirement of long-lived assets through depreciation expense. Retirement costs are not a legal obligation but rather the result of cost-based regulation and are accounted for under the provisions of FASB ASC No. 980. Such amounts are classified as a regulatory liability.

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

Asset Retirement Obligations FASB ASC No. 410, *Asset Retirement and Environmental Obligations*, requires entities to record the fair value of a liability for an asset retirement obligation when there exists a legal obligation for the retirement of the asset. When the liability is initially recorded, the entity capitalizes the cost, thereby increasing the carrying amount of the underlying asset. In subsequent periods, the liability is accreted, and the capitalized cost is depreciated over the useful life of the underlying asset. The Company has recorded asset retirement obligations for its future legal obligations related to purging and capping its distribution mains and services upon retirement, although the timing of such retirements is uncertain.

The Company s composite depreciation rates include a component to provide for the cost of retirement of assets. As a result, the Company accrues the estimated cost of retirement of its utility plant through depreciation expense and creates a corresponding regulatory liability. The costs of retirement considered in the development of the depreciation component include those costs associated with the legal liability. Therefore, the asset retirement obligation is reclassified from the regulatory cost of retirement obligation. If the legal obligations were to exceed the regulatory liability provided for in the depreciation rates, the Company would establish a regulatory asset for such difference with the anticipation of future recovery through rates charged to customers. The Company increased its asset retirement obligation to reflect changes in the estimated cash flows for asset retirements.

The following is a summary of the asset retirement obligation:

	Years Ended September 30	
	2012	**2011**
Balance, beginning of year	$ 3,863,933	$ 3,073,782
Liabilities incurred	63,965	45,100
Liabilities settled	(213,581)	(121,854)
Accretion	221,048	179,472
Revisions to estimated cash flows	315,930	687,433
Balance, end of year	$ 4,251,295	$ 3,863,933

Cash, Cash Equivalents and Short-Term Investments From time to time, the Company will have balances on deposit at banks in excess of the amount insured by the Federal Deposit Insurance Corporation (FDIC). The Company has not experienced any losses on these accounts and does not consider these amounts to be at credit risk. As of September 30, 2012, the Company did not have any bank deposits in excess of the FDIC insurance limits. For purposes of the consolidated statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

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

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

	Years Ended September 30		
	2012	**2011**	**2010**
Balance, beginning of year	$ 66,058	$ 65,275	$ 50,687
Additions charged to bad debt expense	11,588	67,317	140,178
Recoveries of accounts written off	134,331	190,995	194,395
Accounts written off	(146,758)	(257,529)	(319,985)
Balance, end of year	$ 65,219	$ 66,058	$ 65,275

Financing Receivables Financing receivables represent a contractual right to receive money either on demand or on fixed or determinable dates and are recognized as assets on the entity s balance sheet. The Company has two primary types of financing receivables: trade accounts receivable, resulting from the sale of natural gas and other services to its customers, and notes receivable. Trade accounts receivable are short-term in nature and a provision for uncollectible balances is included in the financial statements. The Company s notes receivable represents the balance on a five-year note with a fifteen year amortization for partial payment on the sale of the Bluefield, Virginia natural gas distribution assets to ANGD, LLC in October 2007 and a 24-month note from a customer related to the payment for relocating a portion of a natural gas distribution main. Both notes are performing assets with all payments current. Management evaluates the status of the notes each reporting period to make an assessment on the collectability of the balance. In its most recent evaluation, management concluded that the notes continued to be fully collectible and no loss reserve was required. Either note would be considered past due if either the interest or principal installment were outstanding for more than 30 days after their contractual due date. On October 30, 2012, the Company and ANGD executed an agreement to extend the maturity date of the $952,000 note for an additional year under the same terms as the expiring note with a new maturity date of November 1, 2013.

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

Unbilled Revenues The Company bills its natural gas customers on a monthly cycle basis; however, the billing cycle period for most customers does not coincide with the accounting periods used for financial reporting. As the Company recognizes revenue when gas is delivered, an accrual is made to estimate revenues for natural gas delivered to customers but not billed during the accounting period. The amounts of unbilled revenue receivable included in accounts receivable on the consolidated balance sheets at September 30, 2012 and 2011 were $951,301 and $1,088,611, 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 state and federal consolidated income tax returns.

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

Over/Under-Recovery of Natural Gas Costs Pursuant to the provisions of the Company s Purchased Gas Adjustment (PGA) clause, the SCC provides the Company with a method of passing along to its customers increases or decreases in natural gas costs incurred by its regulated operations, including gains and losses on natural gas derivative hedging instruments. On a quarterly basis, the Company files a PGA rate adjustment request with the SCC to adjust the gas cost component of its rates up or down depending on projected price and activity. Once administrative approval is received, the Company adjusts the gas cost component of its rates to reflect the approved amount. As actual costs will differ from the projections used in establishing the PGA rate, the Company may either over-recover or under-recover its actual gas costs during the period. Any difference between actual costs incurred and costs recovered through the application of the PGA is recorded 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.

Fair Value Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company determines fair value based on the following fair value hierarchy which prioritizes each input to the valuation methods into one of the following three broad levels:

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

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

Level 3 Unobservable inputs for the asset or liability where there is little, if any, market activity which require the Company to develop its own assumptions.

The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets (Level 1) and the lowest priority to unobservable inputs (Level 3). All fair value disclosures are categorized within one of the three categories in the hierarchy. See fair value disclosures below and in Notes 6 and 10.

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

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

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

	Years Ended September 30		
	2012	**2011**	**2010**
Net Income	$ 4,296,745	$ 4,653,473	$ 4,445,436
Weighted average common shares	4,647,439	4,592,713	4,514,262
Effect of dilutive securities:			
Options to purchase common stock	3,510	8,079	13,898
Diluted average common shares	4,650,949	4,600,792	4,528,160
Earnings Per Share of Common Stock:			
Basic	$ 0.92	$ 1.01	$ 0.98
Diluted	$ 0.92	$ 1.01	$ 0.98

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

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

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

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

Derivative and Hedging Activities FASB ASC No. 815, *Derivatives and Hedging*, requires the recognition of all derivative instruments as assets or liabilities in the Company s balance sheet and measurement of those instruments at fair value.

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

The Company periodically enters into collars, swaps and caps for the purpose of hedging the price of natural gas in order to provide price stability during the winter months. The fair value of these instruments is recorded in the balance sheet with the offsetting entry to either under-recovery of gas costs or over-recovery of gas costs. Net income and other comprehensive income are not affected by the change in market value as any cost incurred or benefit received from these instruments is recoverable or refunded through the PGA as the SCC allows for full recovery of prudent costs associated with natural gas purchases. At September 30, 2012 and 2011, the Company had no outstanding derivative instruments for the purchase of natural gas.

The Company also has two interest rate swaps associated with its variable rate notes. The first swap relates to a $15,000,000 note issued in November 2005. This swap essentially converts the floating rate note based upon LIBOR into fixed rate debt with a 5.74% effective interest rate. The second swap relates to the $5,000,000 variable rate note issued in October 2008. This swap converts the variable rate note based on LIBOR into a fixed rate debt with a 5.79% effective interest rate. Both swaps mature on December 1, 2015 and qualify as cash flow hedges with changes in fair value reported in other comprehensive income.

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

The table below reflects the fair values of the derivative instruments and their corresponding classification in the consolidated balance sheets under the current liabilities caption of Fair value of marked-to-market transactions as of September 30, 2012 and 2011:

Fair Value of Derivative Instruments

	September 30	
	2012	**2011**
Derivatives designated as hedging instruments:		
Interest rate swaps	$ 2,916,718	$ 3,312,176
Total derivatives designated as hedging instruments	$ 2,916,718	$ 3,312,176

See Note 10 for additional information on fair value.

Based on the interest rate environment as of September 30, 2012, approximately $930,000 of the fair value of the interest rate hedges will be reclassified from other comprehensive loss into interest expense on the income statement over the next 12 months. Changes in LIBOR rates during that period could significantly change the estimated amount to be reclassified to income as well as the fair value of the interest rate hedges.

Stock Split On July 25, 2011, the Board of Directors of RGC Resources, Inc. declared a two-for-one stock split effected in the form of a 100% share dividend upon the issued and outstanding common stock. The stock dividend was payable on September 1, 2011 to shareholders of record on August 15, 2011. As the par value of the common stock remained at $5 per share, the Company reclassified $11,560,575 from Capital in excess of par value to Common Stock associated with the issuance of 2,312,115 shares. Corresponding prior year amounts, including share and per share data, have been restated retrospectively to reflect the 100% stock dividend.

Other Comprehensive Income(Loss) A summary of other comprehensive income is provided below:

	Before Tax Amount	Tax (Expense) or Benefit	Net-of Tax Amount
Year Ended September 30, 2012:			
Interest rate swaps:			
Unrealized losses	$ (543,826)	$ 206,437	$ (337,389)
Transfer of realized losses to interest expense	939,285	(356,553)	582,732
Net interest rate SWAPs	395,459	(150,116)	245,343
Defined benefit plans:			
Net loss arising during period	(508,666)	193,294	(315,372)
Amortization of actuarial losses	200,136	(76,052)	124,084
Amortization of transition obligation	47,093	(17,895)	29,198
Net defined benefit plans	(261,437)	99,347	(162,090)
Other comprehensive income	$ 134,022	$ (50,769)	$ 83,253
Year Ended September 30, 2011:			
Interest rate swaps:			
Unrealized losses	$ (723,525)	$ 274,652	$ (448,873)
Transfer of realized losses to interest expense	947,894	(359,822)	588,072
Net interest rate SWAPs	224,369	(85,170)	139,199
Defined benefit plans:			
Net loss arising during period	(689,785)	262,119	(427,666)
Amortization of actuarial losses	149,604	(56,850)	92,754
Amortization of transition obligation	47,093	(17,895)	29,198
Net defined benefit plans	(493,088)	187,374	(305,714)
Other comprehensive loss	$ (268,719)	$ 102,204	$ (166,515)
Year Ended September 30, 2010:			
Interest rate swaps:			
Unrealized losses	$ (2,025,678)	$ 768,948	$ (1,256,730)
Transfer of realized losses to interest expense	940,188	(356,896)	583,292
Net interest rate SWAPs	(1,085,490)	412,052	(673,438)
Defined benefit plans:			
Net loss arising during period	(647,439)	246,031	(401,408)
Amortization of actuarial losses	102,478	(38,942)	63,536
Amortization of transition obligation	47,093	(17,900)	29,193
Net defined benefit plans	(497,868)	189,189	(308,679)
Other comprehensive loss	$ (1,583,358)	$ 601,241	$ (982,117)

Composition of Accumulated Other Comprehensive Income (Loss)

	Interest Rate Swaps	Defined Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Balance 10/1/09	$ (1,520,635)	$ (1,364,071)	$ (2,884,706)
Other comprehensive income (loss)	(673,438)	(308,679)	(982,117)
Balance 9/30/10	(2,194,073)	(1,672,750)	(3,866,823)
Other comprehensive income (loss)	139,199	(305,714)	(166,515)
Balance 9/30/11	(2,054,874)	(1,978,464)	(4,033,338)
Other comprehensive income (loss)	245,343	(162,090)	83,253
Balance 9/30/12	$ (1,809,531)	$ (2,140,554)	$ (3,950,085)

Recently Adopted Accounting Standards In July 2010, the FASB issued guidance under FASB ASC No. 310 *Receivables*, to provide greater transparency about an entity s allowance for credit losses and the credit quality of its financing receivables on a disaggregated basis. The new requirements have been adopted and further discussion included in the Financing Receivables section above.

In May 2011, the FASB issued guidance under FASB ASC No. 820 *Fair Value Measurement,* which serves to converge guidance between the FASB and the International Accounting Standards Board (IASB) for fair value measurements and their related disclosures. This guidance provides for common requirements for measuring fair value and for disclosing information about fair value measurements including the consistency of the meaning of the term fair value . This guidance provides clarification about the application of existing fair value measurement and disclosure requirements as well as changes in particular requirements for measuring fair value or for disclosing information about fair value measurements. The new requirements have been included in the disclosures contained in Note 10 below.

In June 2011, the FASB issued guidance under FASB ASC No. 220 *Comprehensive Income* that defines the presentation of Comprehensive Income in the financial statements. According to the guidance, an entity may present a single continuous statement of comprehensive income or two separate statements a statement of income and a statement of other comprehensive income that immediately follows the statement of income. In either presentation, the entity is required to present on the face of the financial statement the components of other comprehensive income including the reclassification adjustment for items that are reclassified from other comprehensive income to net income. In December 2011, the FASB issued additional guidance under FASB ASC No. 220 that deferred the effective date of earlier guidance with regard to the presentation of reclassifications of items out of accumulated other comprehensive income. All other provisions of the original guidance remain in effect. The new requirements have been included in the Consolidated Statements of Comprehensive Income presented in the Company s financial statements. Additional information is provided in the Other Comprehensive Income section above.

Recently Issued Accounting Standards In December 2011, the FASB issued disclosure guidance under FASB ASC No. 210 *Balance Sheet* that requires an entity to disclose information about offsetting and related arrangements that enable users of its financial statements to understand the effect of those arrangements on its financial position. Management is currently evaluating the requirements of this guidance but does not anticipate these changes to have a material impact on its financial position. The new requirements are effective on a retrospective basis for annual reporting periods, and interim periods within those annual periods, beginning on or after January 1, 2013.

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

2. REGULATORY MATTERS

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

On November 1, 2011 the Company placed into effect new base rates, subject to refund, that provided for approximately $1,100,000 in additional non-gas revenues. On May 2, 2012, the SCC issued a final order granting the Company a rate award in the amount of $235,000 in additional non-gas revenues. In June 2012, the Company completed its refund for the difference between the rates placed into effect November 1 and the final rates approved in the Commission order.

On March 15, 2012, the Company filed an application for 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 a mechanism for the Company to recover the related depreciation and expenses and return on rate base of the additional capital investment without the filing of a formal application for an increase in non-gas base rates. This replacement will enhance the safety and reliability of the Company s gas distribution system. On July 25, 2012, the SCC approved the SAVE Plan and Rider, to be effective January 1, 2013.

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 will be able to place the increased rates into effect for service rendered on or 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.

3. SHORT-TERM DEBT

The Company has available an unsecured line-of-credit with a bank which will expire March 31, 2013. The Company anticipates being able to extend or replace this line-of-credit upon expiration. The Company s available unsecured line-of-credit varies during the year to accommodate its seasonal borrowing demands. Available limits under this agreement for the remaining term are as follows:

Effective	Available Line-of-Credit
September 30, 2012	$ 3,000,000
October 25, 2012	5,000,000
January 25, 2013	3,000,000
February 24, 2013	1,000,000

A summary of the line-of-credit follows:

	September 30 2012	2011	2010
Line-of-credit at year-end	$ 3,000,000	$ 3,000,000	$ 3,000,000
Outstanding balance at year-end			
Highest month-end balance outstanding			
Average daily balance			
Average rate of interest during year on outstanding balances	0.00%	0.00%	0.00%
Interest rate at year-end	1.22%	1.24%	1.26%
Interest rate on unused line-of-credit	0.15%	0.15%	0.15%

On March 30, 2012, the Company executed an unsecured term note in the amount of $15,000,000. This 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 including an interest rate of 30-day LIBOR plus 69 basis point spread. The Company also has an interest rate swap related to the $15,000,000 note. This swap was executed in November 2005 in connection with the original promissory note with a maturity date of November 30, 2015. This swap essentially converts the variable rate note into fixed rate debt with a 5.74% interest rate. The Company anticipates being able to extend the maturity date of the $15,000,000 note on an annual basis at terms comparable to the note currently in place until such time the note co-terminates with the corresponding interest rate swap.

4. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30 2012	September 30 2011
Unsecured note payable, with variable interest rate based on 30-day LIBOR plus 69 basis point spread, with provision for retirement on March 31, 2012	$	$ 15,000,000
Unsecured note payable, with variable interest rate based on three month LIBOR (0.35% at September 30, 2012) plus 125 basis point spread, with provision for retirement on December 1, 2015	5,000,000	5,000,000
Unsecured senior note payable, at 7.66%, with provision for retirement of $1,600,000 each year beginning December 1, 2014 through December 1, 2018	8,000,000	8,000,000
Total long-term debt	13,000,000	28,000,000
Less current maturities		(15,000,000)
Total long-term debt	$ 13,000,000	$ 13,000,000

The above debt obligations contain various provisions, including a minimum interest charge coverage ratio, limitations on debt as a percentage of total capitalization and a provision restricting the payment of dividends, primarily based on the earnings of the Company and dividends previously paid. The Company was in compliance with these provisions at September 30, 2012 and 2011. At September 30, 2012, approximately $14,905,000 of retained earnings was available for dividends.

The $15,000,000 unsecured variable rate note was refinanced on March 30, 2012 with a one-year promissory note with a maturity date of March 31, 2013. More information regarding the promissory note is included in Note 3.

The $5,000,000 variable rate note also has an interest rate swap that converts the note into a fixed rate debt with a 5.79% effective interest rate. The interest rate swap matures on December 1, 2015.

The aggregate annual maturities of long-term debt for the next five years ending after September 30, 2012 are as follows:

Year Ending September 30	Maturities
2013	$
2014	
2015	1,600,000
2016	6,600,000
2017	1,600,000
Thereafter	3,200,000
Total	$ 13,000,000

5. INCOME TAXES

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

	Years Ended September 30		
	2012	**2011**	**2010**
Current income taxes:			
Federal	$ (38,608)	$ (178,190)	$ 543,852
State	232,270	263,898	228,008
Total current income taxes	193,662	85,708	771,860
Deferred income taxes:			
Federal	2,269,921	2,586,877	1,746,425
State	184,405	189,224	202,871
Total deferred income taxes	2,454,326	2,776,101	1,949,296
Amortization of investment tax credits	(9,039)	(14,698)	(30,155)
Total income tax expense	$ 2,638,949	$ 2,847,111	$ 2,691,001

Income tax expense for the years ended September 30, 2012, 2011 and 2010 differed from amounts computed by applying the U.S. Federal income tax rate of 34% to earnings before income taxes due to the following:

	Years Ended September 30		
	2012	**2011**	**2010**
Income before income taxes	$ 6,935,694	$ 7,500,584	$ 7,136,437
Income tax expense computed at the federal statutory rate	$ 2,358,136	$ 2,550,199	$ 2,426,389
State income taxes, net of federal income tax benefit	275,005	299,061	284,380
Amortization of investment tax credits	(9,039)	(14,698)	(30,155)
Other, net	14,847	12,549	10,387
Total income tax expense	$ 2,638,949	$ 2,847,111	$ 2,691,001

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

	September 30 2012	September 30 2011
Deferred tax assets:		
Allowance for uncollectibles	$ 24,757	$ 25,075
Accrued pension and postretirement medical benefits	2,698,204	2,487,668
Accrued vacation	232,516	222,233
Over-recovery of gas costs		134,939
Costs of gas held in storage	1,181,336	995,956
Deferred compensation	510,288	514,993
Interest rate swap	1,107,186	1,257,302
Other	279,981	191,919
Total gross deferred tax assets	6,034,268	5,830,085
Deferred tax liabilities:		
Utility plant	14,925,657	12,707,133
Under recovery of gas costs	260,859	
Accrued gas costs	374,321	179,244
Total gross deferred tax liabilities	15,560,837	12,886,377
Net deferred tax liability	$ 9,526,569	$ 7,056,292

FASB ASC No. 740 - *Income Taxes* provides for the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recognized in the financial statements. The Company has evaluated its tax positions and accordingly has not identified any significant uncertain tax positions. The Company s policy is to classify interest associated with uncertain tax positions as interest expense in the financial statements. Penalties are classified under other expense.

The Company files a consolidated federal income tax return and state income tax returns in Virginia and West Virginia. The federal returns and the state returns for both Virginia and West Virginia for the tax years ended prior to September 30, 2009 are no longer subject to examination. An examination of the Company s 2010 federal income tax return was recently completed. The audit did not result in any additional tax being owed.

6. EMPLOYEE BENEFIT PLANS

The Company sponsors both a noncontributory defined benefit pension plan and a postretirement benefit plan (Plans). The defined benefit pension plan covers substantially all employees and benefits fully vest after five years of credited service. Benefits paid to retirees are based on age at retirement, years of service and average compensation. The postretirement benefit plan provides certain healthcare, supplemental retirement and life insurance benefits to retired employees who meet specific age and service requirements. Employees hired prior to January 1, 2000 are eligible to participate in the postretirement benefit plan. Employees must have a minimum of ten years of service and retire after attaining the age of 55 in order to vest in the postretirement plan. Retiree contributions to the plan are based on the number of years of service to the Company as determined under the defined benefit plan.

Employers who sponsor defined benefit plans must recognize the funded status of defined benefit pension and other postretirement plans as an asset or liability in its statement of financial position and recognize changes in that funded status in the year in which the changes occur through comprehensive income. For pension plans, the benefit obligation is the projected benefit obligation, and for other postretirement plans, the benefit obligation is the accumulated benefit obligation. The Company established a regulatory asset for the portion of the obligation expected to be recovered in rates in future periods. The regulatory asset is adjusted for the amortization of the transition obligation and recognition of actuarial gains and losses. The portion of the obligation attributable to the unregulated operations of the holding company is recognized in comprehensive income.

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

	Pension Plan		Postretirement Plan	
	2012	**2011**	**2012**	**2011**
Accumulated benefit obligation	$ 18,993,062	$ 15,339,762	$ 13,707,308	$ 12,185,319
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 19,167,918	$ 17,539,688	$ 12,185,319	$ 11,832,322
Service cost	521,701	479,236	195,777	194,842
Interest cost	953,197	908,873	592,359	579,976
Actuarial loss	3,445,737	727,167	1,128,635	32,342
Benefit payments, net of retiree contributions	(518,102)	(487,046)	(394,781)	(454,163)
Benefit obligation at end of year	$ 23,570,451	$ 19,167,918	$ 13,707,309	$ 12,185,319
Change in fair value of plan assets:				
Fair value of plan assets at beginning of year	$ 12,992,723	$ 12,682,758	$ 7,033,605	$ 6,838,726
Actual return on plan assets, net of taxes	2,488,760	(202,989)	1,184,304	(200,958)
Employer contributions	1,100,000	1,000,000	850,000	850,000
Benefit payments, net of retiree contributions	(518,102)	(487,046)	(394,781)	(454,163)
Fair value of plan assets at end of year	$ 16,063,381	$ 12,992,723	$ 8,673,128	$ 7,033,605
Funded status	$ (7,507,070)	$ (6,175,195)	$ (5,034,181)	$ (5,151,714)
Amounts recognized in the balance sheets consist of:				
Noncurrent liabilities	$ (7,507,070)	$ (6,175,195)	$ (5,034,181)	$ (5,151,714)
Amounts recognized in accumulated other comprehensive loss:				
Transition obligation, net of tax	$	$	$ 22,303	$ 51,500
Net actuarial loss, net of tax	1,568,916	1,354,418	549,335	572,546
Total amounts included in other comprehensive loss, net of tax	$ 1,568,916	$ 1,354,418	$ 571,638	$ 624,046
Amounts deferred to a regulatory asset:				
Transition obligation	$	$	$ 105,699	$ 247,498
Net actuarial loss	5,719,060	4,624,284	3,315,566	3,205,828
Amounts recognized as regulatory assets	$ 5,719,060	$ 4,624,284	$ 3,421,265	$ 3,453,326

The Company expects that approximately $255,000, before tax, of accumulated other comprehensive loss will be recognized as a portion of net periodic benefit costs in fiscal 2013 and approximately $706,000 of amounts deferred as regulatory assets will be amortized and recognized in net periodic benefit costs in fiscal 2013.

The Company amortizes the unrecognized transition obligation over 20 years.

The following table details the actuarial assumptions used in determining the projected benefit obligations and net benefit cost of the pension and the accumulated benefit obligations and net benefit cost of the postretirement plan for 2012, 2011 and 2010.

	Pension Plan			Postretirement Plan		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Assumptions used to determine benefit obligations:						
Discount rate	4.06%	5.04%	5.25%	3.95%	4.96%	5.00%
Expected rate of compensation increase	4.00%	4.00%	4.00%	N/A	N/A	N/A
Assumptions used to determine benefit costs:						
Discount rate	5.04%	5.25%	5.50%	4.96%	5.00%	5.50%
Expected long-term rate of return on plan assets	7.25%	7.25%	7.25%	5.11%	5.09%	5.14%
Expected rate of compensation increase	4.00%	4.00%	4.00%	N/A	N/A	N/A

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

Components of net periodic benefit cost are as follows:

	Pension Plan			Postretirement Plan		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Service cost	$ 521,701	$ 479,236	$ 448,858	$ 195,777	$ 194,842	$ 159,784
Interest cost	953,197	908,873	853,643	592,359	579,976	513,437
Expected return on plan assets	(959,178)	(928,207)	(818,627)	(367,359)	(357,278)	(325,050)
Amortization of unrecognized transition obligation				188,892	188,892	188,892
Recognized loss	475,414	327,173	275,112	239,387	201,151	68,535
Net periodic benefit cost	$ 991,134	$ 787,075	$ 758,986	$ 849,056	$ 807,583	$ 605,598

The assumed health care cost trend rates used in measuring the accumulated benefit obligation for the postretirement medical plan as of September 30, 2012, 2011 and 2010 are presented below:

	Pre 65			Post 65		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Health care cost trend rate assumed for next year	9.00%	10.00%	9.00%	6.00%	7.00%	7.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%	4.75%	5.00%	5.00%	4.75%
Year that the rate reaches the ultimate trend rate	2016	2017	2017	2013	2013	2017

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

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 141,000	$ (112,000)
Effect on accumulated postretirement benefit obligation	2,223,000	(1,800,000)

The primary objectives of the Plan 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 in both the short-term and long-term. The investment policy provides for a range of investment allocations to allow for flexibility in responding to market conditions. The investment policy is periodically reviewed by the Company and a third-party fiduciary for investment matters.

The Company s target and actual asset allocation in the pension and postretirement benefit plans as of September 30, 2012 and 2011 were:

		Pension Plan			Postretirement Plan	
	Target	**2012**	**2011**	**Target**	**2012**	**2011**
Asset category:						
Equity securities	60%	59%	57%	50%	60%	55%
Debt securities	40%	38%	42%	50%	39%	43%
Cash	0%	3%	1%	0%	1%	1%
Other	0%	0%	0%	0%	0%	1%

The assets of the plans are invested in mutual funds. The Company uses the fair value hierarchy described in Note 1 to classify these assets. The mutual funds are included under Level 2 in the fair value hierarchy as their fair values are determined based on individual prices for each security that comprises the mutual funds. Most all of the individual investments are determined based on quoted market prices for each security; however, certain fixed income securities and other investments are not actively traded and are valued based on similar investments. The following table contains the fair value classifications of the benefit plan assets:

		Defined Benefit Pension Plan Fair Value Measurements - September 30, 2012		
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 522,626	$ 522,626	$	$
Common and Collective Trust	2,040,204		2,040,204	
Mutual Funds				
Bonds				
Domestic Fixed Income	3,349,538		3,349,538	
Foreign Fixed Income	631,442		631,442	
Equities				
Domestic Large Cap Growth	3,101,385		3,101,385	
Domestic Large Cap Value	3,114,649		3,114,649	
Domestic Small/Mid Cap Core	1,414,211		1,414,211	
Foreign Large Cap Growth	661,895		661,895	
Foreign Large Cap Core	1,227,431		1,227,431	
Total	$ 16,063,381	$ 522,626	$ 15,540,755	$

		Defined Benefit Pension Plan Fair Value Measurements - September 30, 2011		
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 102,083	$ 102,083	$	$
Common and Collective Trust	1,835,951		1,835,951	
Mutual Funds				
Bonds				
Domestic Fixed Income	3,040,066		3,040,066	
Foreign Fixed Income	600,539		600,539	
Equities				
Domestic Large Cap Growth	2,372,860		2,372,860	
Domestic Large Cap Value	2,321,689		2,321,689	
Domestic Small/Mid Cap Growth	539,157		539,157	
Domestic Small/Mid Cap Value	531,269		531,269	
Foreign Large Cap Growth	585,333		585,333	
Foreign Large Cap Core	1,063,776		1,063,776	
Total	$ 12,992,723	$ 102,083	$ 12,890,640	$

	Postretirement Benefit Plan Fair Value Measurements - September 30, 2012			
	Fair Value	**Level 1**	**Level 2**	**Level 3**
Asset Class:				
Cash	$ 63,991	$ 63,991	$	$
Mutual Funds				
Bonds				
Domestic Fixed Income	3,121,786		3,121,786	
Foreign Fixed Income	226,562		226,562	
Equities				
Domestic Large Cap Growth	1,597,675		1,597,675	
Domestic Large Cap Value	1,719,786		1,719,786	
Domestic Small/Mid Cap Growth	367,369		367,369	
Domestic Small/Mid Cap Value	381,378		381,378	
Domestic Small/Mid Cap Core	35,450		35,450	
Foreign Large Cap Growth	381,020		381,020	
Foreign Large Cap Core	727,867		727,867	
Other	50,244		50,244	
Total	$ 8,673,128	$ 63,991	$ 8,609,137	$

	Postretirement Benefit Plan Fair Value Measurements - September 30, 2011			
	Fair Value	**Level 1**	**Level 2**	**Level 3**
Asset Class:				
Cash	$ 44,677	$ 44,677	$	$
Mutual Funds			&nb	