RGC RESOURCES INC
Form ARS
December 12, 2014
Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Operationally, 2014 was a strong and busy year. The weather was 9% colder than the 30-year average and our total natural gas deliveries exceeded 10 million deka-therms. Industrial demand increased by 6% over last year and we anticipate this higher level of natural gas use to continue next year. We are also excited to provide natural gas service to a new packaging manufacturer, Ardagh Group, which opened a $93 million metal packaging plant with the capability of producing 1.7 billion cans a year.

We invested a record $14.7 million in capital improvements in 2014 and plan to invest approximately $13.5 million in fiscal 2015. We continue to aggressively modernize our distribution system. In 2014, we replaced 13.6 miles of cast iron and bare steel pipe with polyethylene pipe. In 1991, cast iron and bare steel pipe accounted for approximately 25% of our distribution system. At the end of fiscal 2014, it represents less than 2%. Based on the estimated replacement rate, we anticipate replacing all remaining bare steel and cast iron pipe by the end of 2016, further enhancing safety and system reliability. Once we complete the replacement of our bare steel and cast iron mains, our efforts will shift to replacing all pre-1973 plastic mains with current polyethylene pipe. This infrastructure replacement program is forecast to be completed in fiscal 2019. In 2014, we replaced and upgraded one of our primary gas transfer stations and are in the final stages of replacing a critical piece of equipment at our liquefied natural gas facility that is used for peak shaving during extremely cold periods.

INDUSTRIAL DEMAND INCREASED BY 6% OVER LAST YEAR AND WE ANTICIPATE THIS HIGHER LEVEL OF NATURAL GAS USE TO CONTINUE NEXT YEAR.

As the economy continues to gradually improve, we are experiencing improved customer growth. In 2014, new customer additions increased 43% over last year. The new construction segment increased 7%, the conversion segment where existing homes or businesses converted to natural gas from either propane, fuel oil or electric increased 17%, and the balance of the increase was derived from the conversion of an apartment complex to individual gas meters.

We had an active year from a regulatory prospective. The rate case filed in September 2013 was settled favorably with the Virginia State Corporation Commission (SCC) in May 2014, at $887,000 with an authorized return on equity of 9.75%. We filed an updated depreciation study with the SCC in June and received approval of the new depreciation rates in September, resulting in a slight decrease in annual depreciation expense. We filed and received approval on an amendment to a separate regulatory infrastructure replacement plan designed to recover the increased investment carrying costs and depreciation expense associated with future planned infrastructure replacements through calendar year 2018. This includes modernization of our distribution system, replacement of our gas transfer station on

Table of Contents

ON A NATIONAL LEVEL, NATURAL GAS INDUSTRY DATA INDICATES THAT WE HAVE A NATURAL GAS SUPPLY OF OVER 100 YEARS. THIS ABUNDANT AND INCREASINGLY ACCESSIBLE SUPPLY HAS CREATED LOW AND STABLE PRICES ON BOTH A NEAR AND INTERMEDIATE TERM BASIS.

the interstate pipeline, and replacement of a key component at our liquefied natural gas facility. Last, we filed and received approval from the SCC for refinancing our existing long-term debt, which will reduce our annual interest expense going forward.

On a national level, natural gas industry data indicates that we have a natural gas supply of over 100 years. This abundant and increasingly accessible supply has created low and stable prices on both a near and intermediate term basis. Production continues to increase in the various shale formations around the country as natural gas exploration and production companies continue to improve drilling and fracking technologies. As production has increased, so has the demand for new pipelines to move this increased supply to market. Interstate pipeline companies are investing billions of dollars constructing new pipelines and modifying existing pipelines to make them bi-directional so they can efficiently move gas as future demand increases.

In the Commonwealth of Virginia, two pipelines are proposed: Atlantic Coast Pipeline and the Mountain Valley Pipeline. Both are designed to move gas from the Marcellus and Utica shale formations to the Southeast.

The Mountain Valley Pipeline, if constructed, may provide future opportunities to expand our footprint in Virginia to areas that currently do not have access to natural gas.

We are excited to be part of the growing natural gas industry and the pursuit of potential growth opportunities it may bring to our Company. I look forward to reporting to you at the end of 2015 on what I anticipate to be another year of solid performance.

On behalf of our dedicated employees and the Board of Directors, I thank you for your continued interest in our operations and your continuing decision to invest in RGC Resources.

Sincerely,
John D Orazio
President & CEO

Table of Contents

Table of Contents

BOARD OF DIRECTORS

LEFT TO RIGHT: John B. Williamson, III; Nancy Howell Agee; George W. Logan; J. Allen Layman; Raymond D. Smoot, Jr.; Maryellen F. Goodlatte; S. Frank Smith; John S. D Orazio; (Abney S. Boxley, III not pictured)

Table of Contents

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RGC Resources, Inc.

DIRECTOR [3, 4]

Robert L. Wells, II
VICE PRESIDENT, INFORMATION TECHNOLOGY
RGC Resources, Inc.

[1] *RGC Resources, Inc.*

[2] *Roanoke Gas Company*

[3] *Diversified Energy Company*

[4] *RGC Ventures of Virginia, Inc.*

DIRECTOR [3, 4] **DIRECTOR** [3, 4]

Table of Contents

SELECTED FINANCIAL DATA

YEAR ENDING SEPTEMBER 30	2014	2013	2012	2011	2010
Operating Revenues	**$ 75,016,134**	$ 63,205,666	$ 58,799,687	$ 70,798,871	$ 73,823,914
Gross Margin	**29,337,089**	27,602,891	26,933,097	27,269,566	26,440,273
Operating Income	**9,681,868**	8,795,055	8,786,535	9,313,046	8,982,181
Net Income	**4,708,440**	4,262,052	4,296,745	4,653,473	4,445,436
Basic Earnings Per Share	**$ 1.00**	$ 0.91	$ 0.92	$ 1.01	$ 0.98
Cash Dividends Declared Per Share	**$ 0.74**	$ 1.72	$ 0.70	$ 0.68	$ 0.66
Book Value Per Share	**$ 11.02**	$ 10.51	$ 10.85	$ 10.55	$ 10.18
Average Shares Outstanding	**4,715,478**	4,698,727	4,647,439	4,592,713	4,514,262
Total Assets	**$ 139,320,722**	$ 124,526,701	$ 129,756,338	$ 125,549,049	$ 120,683,316
Long-Term Debt (Less Current Portion)	**30,500,000**	13,000,000	13,000,000	13,000,000	28,000,000
Stockholders Equity	**52,020,847**	49,502,422	50,682,930	48,785,778	46,309,747
Shares Outstanding at Sept. 30	**4,720,378**	4,709,326	4,670,567	4,624,682	4,548,864

Table of Contents

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that relate to future transactions, events or expectations. 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, assume, indicate or similar words or future or conditional verbs su 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.

Table of Contents

MANAGEMENT S DISCUSSION & ANALYSIS

OVERVIEW

Resources is an energy services company primarily engaged in the regulated sale and distribution of natural gas to approximately 58,600 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 integrity of its transmission and distribution pipelines. The Federal Energy Regulatory Commission regulates 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 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 modernization of its distribution system through the renewal and replacement of its cast iron and bare steel natural gas distribution pipelines. With recent regulatory actions placing a greater emphasis on pipeline safety, the Company continues to focus its efforts on completing its renewal and replacement program. Management anticipates replacing all remaining cast iron and bare steel pipe within the next three 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 will execute its Security Incident Response Plan to assist with managing the incident. The Company also maintains cyber-insurance coverage to mitigate financial implications resulting from a breach of confidential information.

Over 97% of the Company s revenues are derived through the regulated operations of Roanoke Gas primarily associated with the sale and delivery of natural gas to its customers. The SCC authorizes the rates and fees that the Company charges its customers for these services. 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 based on normal weather. Normal weather refers to the average number of heating degree days (an industry measure by which the average daily temperature falls below 65 degrees Fahrenheit) over the previous 30-year period.

The Company s business is seasonal in nature and weather sensitive 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 return for its shareholders. In order to mitigate the effect of weather variations, the Company has certain approved rate mechanisms that help provide stability in earnings. These mechanisms include a weather normalization adjustment factor, inventory carrying cost revenue and a SAVE adjustment rider.

The weather normalization adjustment mechanism (WNA) reduces the volatility in earnings due to the variability in temperatures during the heating season. The WNA is based on a weather measurement band around the most recent 30-year temperature average. The WNA provides the Company with a level of earnings protection

Table of Contents

when weather is warmer than normal and provides its customers with price protection when the weather is colder than normal. Through March 31, 2014, the WNA provided 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 WNA periods ending March 31, 2014, 2013 and 2012, the number of heating degree days were 10% colder than normal, less than 3% warmer than normal and 22% warmer than normal, respectively. As a result, the Company refunded customers approximately $707,000 in excess margin in fiscal 2014 and billed customers approximately $1,747,000 in additional margin in fiscal 2012. No billing or refunds were required in fiscal 2013 as the number of heating degree days fell within the 3% band. Effective with the new WNA period beginning April 1, 2014, the 3% weather band was eliminated and the WNA is now based strictly on the variations from normal. At September 30, 2014, the number of heating degree days for the six month period was less than the 30-year average and the Company accrued approximately $144,000 in additional margin. Additional information on the WNA is provided under the Regulatory Affairs section.

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 (ICC) 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 declining inventory balances, the Company recognizes less carrying cost revenue as financing costs are lower. Although the total cost of natural gas in storage, as well as the cost per decatherm, at September 30, 2014 was higher than the cost in storage at September 30, 2013, the average balance during the year was down by more than 4% due to greater level of storage withdrawals during a much colder 2013-2014 winter season. In addition, the ICC factor declined by 2%, resulting in a reduction in ICC revenues of $58,000. Fiscal 2013 reflected a $299,000 reduction in ICC revenues due to a 14% lower average balance of natural gas in storage as compared to fiscal 2012.

Table of Contents

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.

The Company s non-gas rates provide for the recovery of non-gas related expenses and a reasonable return to shareholders. These rates are determined based on the filing of a formal rate application with the SCC utilizing historical information including investment in natural gas facilities. Generally, investments related to extending service to new customers are recovered through the non-gas rates currently in place. The investment in replacing and upgrading existing infrastructure is not recoverable until a formal rate application is made to

include the additional investment and new non-gas rates are approved. The SAVE (Steps to Advance Virginia s Energy) Plan and Rider provides the Company with the ability to recover costs related to these investments on a prospective basis rather than on a historical basis. Additional information regarding the SAVE Rider is provided under the Regulatory Affairs section.

The economic environment has a direct correlation with business and industrial production, customer growth and natural gas utilization. The local economy continues to show signs of improvement from the economic downturn that began in 2008, as industrial production activities and the related interruptible and transportation sales to support those activities have returned to pre-2008 levels. Although there are signs of improvement, residential construction and housing starts continue to remain below historical levels. If economic stagnation were to return, industrial activity and new customer growth could be negatively impacted. In addition to economic considerations, natural gas consumption continues to be affected by technological and efficiency improvements in heating equipment.

Table of Contents

Results of Operations

Fiscal Year 2014 Compared with Fiscal Year 2013

The table below reflects operating revenues, volume activity and heating degree-days.

OPERATING REVENUES

YEAR ENDING SEPTEMBER 30	2014	2013	Increase / (Decrease)	Percentage
Gas Utilities	**$ 73,865,487**	$ 62,024,174	$ 11,841,313	19%
Other	**1,150,647**	1,181,492	(30,845)	-3%
Total Operating Revenues	**$ 75,016,134**	$ 63,205,666	$ 11,810,468	19%

DELIVERED VOLUMES

YEAR ENDING SEPTEMBER 30	2014	2013	Increase	Percentage
Regulated Natural Gas (DTH)				
Residential and Commercial	**7,005,920**	6,498,783	507,137	8%
Transportation and Interruptible	**3,081,731**	2,910,111	171,620	6%
Total Delivered Volumes	**10,087,651**	9,408,894	678,757	7%
Heating Degree Days (Unofficial)	**4,351**	4,001	350	9%

Total gas utility operating revenues for the year ended September 30, 2014 increased by 19% from the year ended September 30, 2013. The increase in gas revenues was primarily attributable to a combination of a 7% increase in total delivered natural gas volumes, a 30% per decatherm increase in the average commodity price of natural gas, implementation of a non-gas rate increase and higher SAVE Plan revenues. The increase in delivered volumes was driven by the colder winter heating season

where total heating degree days increased by 9% over fiscal 2013 and were above the 30-year average by the same percentage. Transportation and interruptible volumes, which are primarily driven by production activities rather than weather, increased by 6%. Other revenues decreased by 3% due to the completion of a one-time project during the prior year more than offsetting increases in the level of certain other contract services during the current year.

Table of Contents

GROSS MARGIN

YEAR ENDING SEPTEMBER 30	2014	2013	Increase	Percentage
Gas Utility	**$ 28,774,213**	$ 27,108,112	$ 1,666,101	6%
Other	**562,876**	494,779	68,097	14%
Total Gross Margin	**$ 29,337,089**	$ 27,602,891	$ 1,734,198	6%

Regulated natural gas margins from utility operations increased by 6% from fiscal 2013, primarily as a result of higher residential and commercial sales volumes, the implementation of a non-gas rate increase and the addition of the SAVE Plan rider. Residential and commercial volumes (which are strongly correlated to the weather) increased due to the much colder winter season. The higher margins generated by the increased residential and commercial volume were mostly offset by a net WNA refund of $563,000 recognized in fiscal 2014. The Company also implemented a non-gas rate increase effective November 1, 2013 and an increased SAVE Plan Rider beginning January 1, 2014. The non-gas rate increase was designed to provide approximately $887,000 in additional annual non-gas revenues. The implementation of the increased non-gas rates in November accounted for approximately $422,000 of the increase in customer base charges, a flat monthly fee billed to each natural gas customer, and $474,000 of the additional volumetric revenue. The SAVE Plan Rider, as discussed in more detail in the Regulatory Affairs section below, provided an additional $123,000 in margin. ICC revenues continued to decline with a $58,000 reduction in fiscal 2014 compared to fiscal 2013 due to the larger storage withdrawals and lower ICC factor.

Other margins, consisting of non-utility related services, increased by $68,097 due to an increased level of activity under one of the contracted services. The service contracts that comprise most of the non-utility related activities are subject to annual or semi-annual renewal provisions and the potential exists that these contracts may not be renewed or extended by the customer. In addition, the level of activity under these contracts will fluctuate based on customer requirements.

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

NET UTILITY MARGIN INCREASE

Customer Base Charge	$ 659,671
Volumetric	1,493,353
SAVE Plan	123,199
WNA	(563,187)
Carrying Cost	(58,303)
Other	11,368
Total	$ 1,666,101

Table of Contents

OPERATIONS AND MAINTENANCE EXPENSE Operations and maintenance expenses increased by $529,789, or 4%, in fiscal 2014 compared with fiscal 2013 primarily due to higher labor costs, contracted services, bad debt expense and corporate insurance expense more than offsetting significant reductions in employee benefit costs and greater capitalization of Company overheads on construction projects and LNG (liquefied natural gas) production. Labor costs and contracted services increased by $1,128,000 primarily due to a full year of increased operations staffing, timing of pipeline right-of-way clearing, a full year of costs related to an SCC mandated meter installation inspection and remediation program, expenses related to updating the Company s corrosion control processes, benefit consulting services and network services support and training. Bad debt expense increased by approximately $64,000 related to much higher customer billings due to a colder winter heating season. Corporate property and liability insurance increased by $93,000 due to a combination of higher premiums and increased general liability coverage limits. Insurance premiums are expected to increase in fiscal 2015 as well but at a lesser amount. These higher costs were partially offset by a $605,000 reduction in employee benefit expenses, specifically in the defined benefit pension plan (pension plan) and the postretirement medical and life insurance plan (postretirement plan). These actuarially determined expenses declined in fiscal 2014 due to a combination of a higher discount rate for valuing both plans liabilities at September 30, 2013 and strong investment performance of both plans assets. More information on these plans and the impact on the financial statements are provided under the Pension and Postretirement Benefits section of the Critical Accounting Policies and Estimates below and in Note 6 of the financial statements. In addition, $339,000 of additional overheads was capitalized due to a significantly higher level of construction expenditures related to the Company s renewal program and other projects. Total capital expenditures rose by more than $4.7 million over the prior year. The remaining increase of $188,000 relates to a variety of areas including additional facility and equipment maintenance and support costs, higher utility expenses and increased administrative costs related to the Company s operations.

GENERAL TAXES General taxes increased $79,640, or 5%, primarily due to higher property taxes associated with increases in utility property and greater payroll taxes related to increased operations staffing.

DEPRECIATION Depreciation expense increased by $237,956, or 5%, corresponding to the increase in utility plant investment partially offset by lower depreciation rates.

OTHER EXPENSE Other expense, net, increased by $146,770 primarily due to the absence of interest income related to the ANGD note which was paid off in fiscal 2013 combined with a greater level of corporate charitable giving and increased SCC pipeline assessments.

INTEREST EXPENSE Total interest expense remained virtually unchanged from last year as the Company benefited in September from lower interest expense due to its debt refinancing which offset the increased interest incurred under the line- of-credit.

INCOME TAXES Income tax expense increased by $294,753 on higher pre-tax earnings. The effective tax rate for fiscal 2014 was 38.4% compared to 38.3% for 2013.

NET INCOME AND DIVIDENDS Net income for fiscal 2014 was $4,708,440 compared to $4,262,052 for fiscal 2013. Basic and diluted earnings per share were $1.00 in fiscal 2014 compared to $0.91 in fiscal 2013. Dividends declared per share of common stock were $0.74 in fiscal 2014 compared to $1.72 in fiscal 2013, which included the one-time special dividend of $1.00.

Table of Contents

Fiscal Year 2013 Compared with Fiscal Year 2012

The table below reflects operating revenues, volume activity and heating degree-days.

OPERATING REVENUES

YEAR ENDING SEPTEMBER 30	2013	2012	Increase	Percentage
Gas Utilities	$ 62,024,174	$ 57,657,940	$ 4,366,234	8%
Other	1,181,492	1,141,747	39,745	3%
Total Operating Revenues	$ 63,205,666	$ 58,799,687	$ 4,405,979	7%

DELIVERED VOLUMES

Year Ended September 30,	2013	2012	Increase / (Decrease)	Percentage
Regulated Natural Gas (DTH)				
Residential and Commercial	6,498,783	5,335,836	1,162,947	22%
Transportation and Interruptible	2,910,111	2,981,660	(71,549)	-2%
Total Delivered Volumes	9,408,894	8,317,496	1,091,398	13%
Heating Degree Days (Unofficial)	4,001	3,189	812	25%

Total gas utility operating revenues for the year ended September 30, 2013 increased by 7% from the year ended September 30, 2012. The increase in gas revenues was primarily attributable to a 22% increase in residential and commercial delivered volumes, partially offset by lower natural gas commodity prices during the winter heating season. The increase in delivered volumes was driven by the much colder winter heating season compared to

fiscal 2012, evidenced by the 25% increase in heating degree days. Although the total heating degree days increased significantly, the fiscal 2013 year weather was nearly equal to the 30-year average. Transportation and interruptible volumes declined by 2%. Other revenues increased by 3% due to the completion of a one-time project more than offsetting declines in the level of certain other contract services.

Table of Contents

GROSS MARGIN

YEAR ENDING SEPTEMBER 30	2013	2012	Increase / (Decrease)	Percentage
Gas Utility	$ 27,108,112	$ 26,379,767	$ 728,345	3%
Other	494,779	553,330	(58,551)	-11%
Total Gross Margin	$ 27,602,891	$ 26,933,097	$ 669,794	2%

Regulated natural gas margins from utility operations increased by 3% from fiscal 2012 primarily as a result of significantly higher residential and commercial sales volumes, the implementation of a non-gas rate increase and the addition of the SAVE Plan rider. Residential and commercial volumes increased due to the much colder winter season. The higher margins generated by the increased residential and commercial volume were mostly offset by the $1,747,000 in WNA revenues recorded in fiscal 2012. The Company also implemented a non-gas rate increase effective November 1, 2012 and a SAVE Plan Rider beginning January 1, 2013. The non-gas rate increase was designed to provide approximately $650,000 in additional non-gas revenues annually. The implementation of the increased rates in November accounted for approximately $254,000 of the increase in customer base charges and $328,000 of the additional volumetric revenue. The SAVE Plan Rider provided $169,000 in margin. Carrying cost revenues continued to decline with a $299,000 reduction due to lower average price of gas in storage during the fiscal 2013 year.

Other margins, consisting of non-utility related services, decreased by $58,551 due to a reduction in the level of services. Some of these non-utility services are subject to annual or semi-annual contract renewals and the level of activity under these contracts will fluctuate.

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

NET UTILITY MARGIN INCREASE

Customer Base Charge	$ 279,872
Volumetric	2,343,618
SAVE Plan	168,747
WNA	(1,747,150)
Carrying Cost	(299,029)
Other	(17,713)
Total	$ 728,345

Table of Contents

OPERATIONS AND MAINTENANCE EXPENSE Operations and maintenance expenses increased by $305,906, or 2%, in fiscal 2013 compared with fiscal 2012 primarily due to higher labor costs, contracted services, bad debt expense, corporate insurance expense and stock option expense more than offsetting greater capitalization of Company overheads on construction projects and LNG (liquefied natural gas) production. Labor costs and contracted services increased by $453,000 primarily due to an increase in operations staffing, timing of leak surveys and pipeline right-of-way clearing, costs related to an SCC mandated meter installation inspection and remediation program, and network services support and training. Bad debt expense increased by approximately $74,000. Total bad debt expense was 0.13% of gross natural gas billings for fiscal 2013 and is consistent with the five-year average. Fiscal 2012 s bad debt expense ratio was only 0.02%. This unusually low rate was due to much warmer weather and low gas prices, resulting in the lowest bad debt write-off in over twenty-five years. Corporate property and liability insurance increased by $126,000 due to a combination of higher premiums and increased general liability coverage limits. The Company also recognized $85,000 in expense related to the granting of stock options. These were the first option grants since 2002. These higher costs were partially offset by greater capitalization of overheads due to a higher level of pipeline construction expenditures and increased LNG production. The Company continued to increase activity under its pipeline renewal program, with total capital expenditures rising by more than $1.3 million over fiscal 2012, resulting in a greater capitalization of overheads.

GENERAL TAXES General taxes increased $114,066, or 8%, primarily due to higher property taxes associated with increases in utility property.

DEPRECIATION Depreciation expense increased by $241,302, or 6%, corresponding to the increase in utility plant investment.

OTHER INCOME (EXPENSE) Other expense, net, increased by $40,161 primarily due to the reduction in interest income related to the payoff of the ANGD note in fiscal 2013.

INTEREST EXPENSE Total interest expense remained virtually unchanged from fiscal 2012 as the Company only briefly accessed its line-of-credit during fiscal 2013.

INCOME TAXES Income tax expense was nearly unchanged on slightly less pre-tax earnings. The effective tax rate for fiscal 2013 was 38.3% compared to 38.0% for 2012.

NET INCOME AND DIVIDENDS Net income for fiscal 2013 was $4,262,052 compared to $4,296,745 for fiscal 2012. Basic and diluted earnings per share were $0.91 in fiscal 2013 compared to $0.92 in fiscal 2012. Dividends declared per share of common stock were $1.72 in fiscal 2013, which includes the onetime special dividend of $1.00 paid in December 2012, compared to $0.70 in fiscal 2012.

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 2,071,000 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.

Table of Contents

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 receivables and payment of dividends. To meet these needs, the Company relies on its

operating cash flows, line-of-credit agreement, long-term debt, and to a lesser extent, capital raised through the Company s stock plans.

Cash and cash equivalents decreased by $1,996,467 in fiscal 2014 compared to a decrease of $6,063,647 in fiscal 2013 and an increase of $958,442 in fiscal 2012. The following table summarizes the categories of sources and uses of cash:

CASH FLOW SUMMARY

YEAR ENDING SEPTEMBER 30	2014	2013	2012
Provided by operating activities	**$ 6,839,738**	$ 10,037,070	$ 11,783,041
Used in investing activities	**(14,698,570)**	(9,947,510)	(8,650,715)
Provided by (used in) financing activities	**5,862,365**	(6,153,207)	(2,173,884)
Increase (decrease) in cash and cash equivalents	**$ (1,996,467)**	$ (6,063,647)	$ 958,442

As discussed below, the Company increased its capital spending in fiscal 2014 and financed the increase through operating cash flow and utilization of the line-of-credit.

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 and rising customer receivable balances.

Cash provided by operating activities was $6,840,000 in fiscal 2014, $10,037,000 in fiscal 2013 and $11,783,000 in fiscal 2012. Cash provided by operating activities declined by approximately $3,197,000 from last year primarily as a result of a significant move from an over-recovery of gas costs to an under-recovery position during fiscal 2014. As provided under the provisions of the Company s Purchased Gas Adjustment (PGA) clause, the Company

is allowed to recover the actual cost of natural gas from its customers. Any amounts billed in excess of the actual cost are considered an over-recovery of these costs and are reflected as a liability on the financial statements. Conversely, any actual costs incurred in excess of amounts billed are considered an under-recovery of gas costs and are reflected as an asset on the financial statements. During fiscal 2014, the Company went from an over-recovered position of $1,027,000 to an under-recovered position of $181,000, which used $1,208,000 in operating cash. Conversely, during fiscal 2013, the Company went from an under-recovered position of $687,000 to an over-recovered position of $1,027,000, which generated $1,714,000 in operating cash. Increases in operating cash flows due to greater contributions from net income and depreciation offset the impact of increased investment in gas in storage and other operating variances.

Cash provided by operating activities decreased for fiscal 2013 from fiscal 2012 by $1,746,000 due to an increase in cost of gas in storage partially offset by an over-recovery on gas costs and the tax deferral benefits of bonus depreciation. The cost of gas in storage had declined for the last few years as the commodity price of gas declined; however, when the Company began its fiscal 2013 summer storage program to refill

the storage balances,

Table of Contents

the commodity price of gas was higher than fiscal 2012 resulting in higher storage balances by year-end. The average price of natural gas in storage was $4.08 and $3.51 as of September 30, 2013 and 2012, respectively. During fiscal 2013, the Company had a $1,714,000 operating source of cash as the Company went from an under-recovered position to an over-recovered position. During fiscal 2012, the Company had an operating use of cash of $1,043,000 as the Company went from an over-recovered position to an under-recovered position. In addition, 50% bonus depreciation for tax purposes was in place for fiscal 2013 resulting in the Company s deferred income tax liability associated with its utility property increasing by $1,700,000 in fiscal 2013 and more than $2,200,000 in fiscal 2012, thereby deferring payment of income taxes until future periods. The deferred tax liability related to utility property increased by less than $500,000 in fiscal 2014 as bonus depreciation expired December 31, 2013. The Company has approximately $17,100,000 in deferred tax liabilities related to accelerated and bonus depreciation at September 30, 2014 on its utility plant that will begin to reverse in 2015 or later resulting in additional cash outflows for payment of the deferred taxes.

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 expansion of its natural gas system to meet the demands of customer growth. The Company s expenditures related to its pipeline renewal program and other system and infrastructure improvements and expansion have continued to trend upward with more than $14,700,000 spent in fiscal 2014 compared to approximately $10,000,000 in fiscal 2013 and $8,700,000 in fiscal 2012. The Company renewed 13.6 miles of bare steel and cast iron natural gas distribution main and replaced 942 services in fiscal 2014. This compares to 13 miles main and 1,064 services in fiscal 2013 and 15.8 miles of main and 1,429 services in fiscal 2012. Total costs related to the renewal program are higher this year even though the total miles of mains were slightly higher and the number of services replaced were less than last year. As the renewal program has progressed, most of the less complex and more highly concentrated areas of the Company s natural gas distribution system have been completed leaving the more difficult and smaller sections to be done. Completion of the remaining pipeline replacement will more than likely be at a higher per foot cost. The Company s capital expenditures also included costs to extend mains and services to 673 new customers in fiscal 2014 compared to 468 in fiscal 2013 and 450 in fiscal 2012. In addition, the Company completed the replacement of its Gala transfer station and made significant progress in the replacement of the boil off compressor at the LNG plant.

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 cast iron and bare steel pipe within the next three years. As a reflection of this commitment, the Company s capital budget for next year currently is estimated to be near the fiscal 2014 level as work continues on the pipeline replacement program and the installation of a new boil off compressor at the LNG plant is completed. Depreciation provided approximately 33% of the current year s capital expenditures compared to 47% for 2013 and 51% for 2012. Upon completion of the bare steel and cast iron pipe replacement, the Company plans

Table of Contents

to direct its efforts to replacing all pre-1973 plastic mains with current polyethylene pipe. This project encompasses approximately 40 miles of natural gas main with a 2019 anticipated completion. With future capital expenditures projected to remain at higher than historical levels over these next few years, the Company expects to increase its borrowing activity.

CASH FLOWS PROVIDED BY (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 mentioned above, the Company uses its line-of-credit arrangement to fund seasonal working capital and provide temporary financing for capital projects. Cash flows provided by financing activities were $5,862,000 for fiscal 2014 compared to cash flows used in financing activities of $6,153,000 for fiscal 2013 and $2,174,000 for fiscal 2012. The Company experienced significant activity in financing cash flows in 2014. The Company refinanced $28,000,000 of its debt, including $2,238,000 in early termination fees on the notes and corresponding interest rate swaps, with $30,500,000 in unsecured 20-year term notes. The early termination fees have been deferred as a regulatory asset and will be amortized over the term of the new notes as a component of interest expense. The $28,000,000 in retired debt had an average interest rate of 6.30% with an effective rate of 6.43%. The new debt has a stated interest rate of 4.26% and an effective rate of 4.67%. The Company will realize approximately $376,000 in lower annual interest expense as a result of the refinancing. The Company also increased the utilization of its line-of-credit to fund both the Company s seasonal working capital needs as well as bridge financing for its capital budget. At the current level of capital expenditures, operating cash flows are not sufficient to meet both the capital expenditure requirements and the payment of dividends. Dividends returned to normal levels in fiscal 2014 at an annual rate of $0.74 per share. Last year included a special $1.00 per share dividend paid by the Company on December 17, 2012. The special dividend totaled $4,675,337, of which $425,630 was returned

to the Company under the DRIP Plan. The Company s consolidated capitalization was 63.0% equity and 37.0% long-term debt at September 30, 2014. This compares to 63.9% equity and 36.1% debt, including the note payable, at September 30, 2013. Including the line-of-credit as part of total consolidated capitalization, September 30, 2014 ratios would be 56.8% equity and 43.2% debt.

The remaining difference in financing activities related to the receipt of the pay-off of the balance on the two notes in fiscal 2013 offset by an increase in the regular annual dividend payment rate from $0.72 per share to $0.74 per share.

On March 31, 2014, 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 with an increase in the total borrowing limit. 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 $19,000,000 during the term of the agreement. The upper limit of the line-of-credit increased over prior years due to expected capital expenditure funding needs. The line-of-credit agreement will expire March 31, 2015, 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.

Off-Balance Sheet Arrangements

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

Table of Contents

Contractual Obligations and Commitments

The Company has incurred various contractual obligations and commitments in the normal course of business. As of September 30, 2014, the estimated recorded and unrecorded obligations are as follows:

	Less than 1 year	1-3 years	4-5 years	After 5 years	Total
RECORDED CONTRACTUAL OBLIGATIONS:					
Long-Term Debt[1]	$	$	$	$ 30,500,000	$ 30,500,000
Short-Term Debt[2]	9,045,050				9,045,050
Total	$ 9,045,050	$	$	$ 30,500,000	$ 39,545,050

(1) See Note 4 to the consolidated financial statements.
(2) See Note 3 to the consolidated financial statements.

	Less than 1 year	1-3 years	4-5 years	After 5 years	Total
UNRECORDED CONTRACTUAL OBLIGATIONS, NOT REFLECTED IN CONSOLIDATED BALANCE SHEET IN ACCORDANCE WITH U.S. GAAP:					
Pipeline and Storage Capacity[3]	$ 11,383,418	$ 21,330,892	$ 13,903,581	$ 2,411,198	$ 49,029,089
Gas Supply[4]					
Interest on Short-Term Debt[5]	19,884				19,884
Interest on Long-Term Debt[6]	913,119	2,598,600	2,598,600	19,875,681	25,986,000
Pension Plan Funding[7]					
Other Obligations[8]	89,828	110,750	19,339	26,880	246,797
Total	$ 12,406,249	$ 24,040,242	$ 16,521,520	$ 22,313,759	$ 75,281,770

(3) Recoverable through the 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) Accrued interest on line-of-credit balance at September 30, 2014 including minimum facility fee on unused line-of-credit. See Note 3 to the consolidated financial statements.
(6) See Note 4 to the consolidated financial statements.
(7) Estimated minimum funding requirements beyond five years is not available. See Note 6 to the consolidated financial statements.
(8) Various lease, maintenance, equipment and service contracts.

Table of Contents

Regulatory Affairs

On November 1, 2013, the Company placed into effect new base rates, subject to refund, that would provide approximately $1,664,000 in additional annual non-gas revenues. On March 17, 2014, the Company reached a stipulated agreement with the SCC staff that would provide $887,062 in annual non-gas revenues. A hearing was held on March 25, 2014 resulting in the approval of the stipulated agreement. The stipulation provided for a 9.75% authorized return on equity as was previously in place; however, this was below the 10.1% requested by the Company in the rate filing. On May 9, 2014, the SCC issued its final order approving the increase in annual non-gas revenues agreed to in the stipulation. The Company completed its refund of revenues collected in excess of the approved rates plus interest to its customers in the Company s fiscal third quarter.

In connection with the order approving the non-gas rate award, the SCC also approved a change to the Company s WNA mechanism. Previously, the WNA provided for a weather band of 3% above or below the 30-year temperature average whereby the Company would recover from its customers the lost margin (excluding gas costs) from the impact of weather that was more than 3% warmer than the 30-year average or refund to customers the excess earned from weather that is more than 3% colder than the 30-year average. The WNA is an important regulatory feature for the Company. As the Company s non-gas rates are established and approved by the SCC based on the 30-year average temperatures, weather that is warmer than the 30-year average will result in the Company earning less than what they are allowed under the rates, while weather that is colder than the 30-year average will result in the Company earning at a level above what the rates were designed. The weather band reduced the volatility in earnings due to weather by limiting both the upside and the downside to a 3% swing in weather. During the WNA year ended March 31, 2014, the number of heating degree days were more than 10% colder than the 30-year average. As a result, the Company refunded to customers $707,000 in margin for the additional sales resulting from weather that was between 3% and 10% colder than the 30-year average. The Company was able to keep the additional margin earned on weather up to the 3% weather band.

Effective with the WNA period that began April 1, 2014, the SCC removed the 3% weather band. The WNA will

now result in either a recovery or refund of revenues due to any variation from the 30-year average. Although the model to calculate and adjust for the impact of the deviation from the 30-year average has some limitations, it provides the Company with a more predictable utility operating margin that better aligns with the authorized return as provided for in the Company s utility billing rates. As of September 30, 2014, the Company accrued $144,000 in WNA revenues attributable to weather that had 58 fewer heating degree days than the 30-year average during the first six months of the new WNA period.

On June 4, 2014, the Company filed an application with the SCC requesting approval to extend its authority to incur short-term indebtedness of up to $30,000,000 and to issue up to $60,000,000 in long-term debt securities as part of its long-term financing plan, which included the refinancing of higher interest rate debt and funding for the Company s pipeline replacement program and other infrastructure projects. On June 25, 2014, the SCC issued an order granting the approval of the Company s request.

On June 30, 2014, the Company filed an application for modification of the SAVE (Steps to Advance Virginia s Energy) Plan and Rider. The original SAVE Plan and Rider were approved by the SCC through an order issued on August 29, 2012 and was amended on August 16, 2013. The original SAVE Plan was designed to facilitate the accelerated replacement of the remaining bare steel and cast iron natural gas pipe 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. With the amendment, the Company added two unique projects; the replacement of the boil-off compressor at the Company s LNG plant and replacement of the natural gas transfer station located in Gala, VA. The Plan was amended again in June 2014 to increase the expected investment for the continued replacement of the Company s natural gas distribution pipe and added the investment for the related meter and regulator installations located on customer premises for the 2015 SAVE Plan year. All of these projects included under the SAVE Plan will enhance the safety and reliability of the Company s gas distribution system. In addition, the recovery of the depreciation and related expenses on these projects through the SAVE Plan rider will allow the Company to forego a formal non-gas rate increase at this time.

Table of Contents

The Company s provision for depreciation is computed principally based on composite rates determined by depreciation studies. These depreciation studies are required to be performed on the regulated utility assets of Roanoke Gas Company at least every five years. In June 2014, the Company filed an updated depreciation study with the SCC to update the previous study that was implemented in fiscal 2009. The SCC approved new rates in September 2014 which resulted in a small reduction in the overall composite depreciation rate from 3.35% to 3.25%. The new rates were implemented retroactive to October 1, 2013.

In 2013, the SCC issued new inspection protocols requiring all meter installations to be inspected once every three years, on a continuous cycle. The Company has implemented the program and the inspection and remediation program is ongoing.

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 statements 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 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 also bills customers through a SAVE Rider that provides a mechanism to recover on a prospective basis the costs associated with the Company s expected investment related to the replacement of natural gas distribution pipe and other qualifying projects. As required under the provisions of FASB ASC No. 980, Regulated Operations, the Company recognizes billed revenue related to the SAVE projects to the extent such revenues have been earned under the provisions of the SAVE Plan.

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

Table of Contents

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 $1,071,128 and $1,056,253 as of September 30, 2014 and 2013, respectively.

ALLOWANCE FOR DOUBTFUL ACCOUNTS The Company evaluates the collectability 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, differences in actual returns on plan assets, different rates of medical inflation, 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 utilized 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 4.22% and 4.10% for valuing its pension plan liability and postretirement plan liability at September 30, 2014, representing a decrease of 0.60% and 0.63% in their respective rates from the prior year. The decrease in the discount rates corresponded with similar decreases in long-term interest rates. The 30-year Treasury rate decreased from 3.69% to 3.21%. Likewise, the Moody s Aaa and Moody s Baa decreased by 0.51% and 0.58%, respectively. The decrease in discount rates for valuing the benefit liabilities nearly reversed the increase in rates experienced in the prior fiscal year. The pension and postretirement plan liability discount rates increased by 0.76% and 0.78% for the September 30, 2013 valuation from those used for the September 30, 2012 valuation. The decrease in the discount rates for both plans resulted in a significant increase in the benefit obligation at September 30, 2014. Both plans experienced better than expected returns on the related pension and postretirement assets, which partially offset the deterioration in the funded status of both plans due to the reduction in the discount rates used to value both plans liabilities. As a result of the larger funded deficit, pension and postretirement medical plan expense will increase in fiscal 2015 due to an increase in the amortization of the actuarial loss due to the reduction in the discount rate and an increase in life expectancy assumptions as discussed below. The following tables reflect the funded status of both plans at the corresponding fiscal year ends.

Table of Contents

FUNDED STATUS SEPTEMBER 30, 2014	Pension	Postretirement	Total
Benefit obligation	**$ 24,636,695**	**$ 14,983,169**	**$ 39,619,864**
Fair value of assets	**20,514,179**	**10,646,249**	**31,160,428**
Funded status	**$ (4,122,516)**	**$ (4,336,920)**	**$ (8,459,436)**

FUNDED STATUS SEPTEMBER 30, 2013	Pension	Postretirement	Total
Benefit obligation	$ 21,468,769	$ 13,028,628	$ 34,497,397
Fair value of assets	18,801,262	10,114,062	28,915,324
Funded status	$ (2,667,507)	$ (2,914,566)	$ (5,582,073)

The current economic environment makes it difficult to project interest rates and future investment returns. If the economy improves, long-term interest rates could increase, reducing the benefit liabilities and increasing the investment returns. However, if the economy stagnates or declines, interest rates could remain at these lower levels or even drop, leading to an increase in the benefit liabilities and potential reduction in investment returns. The Company also annually evaluates 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 on the pension plan and a targeted allocation of 50% equity and 50% fixed income for the postretirement plan. As a result of this evaluation, the Company set its expected annual return on pension assets at 7.00% and postretirement assets at 4.90% (net of income taxes) for fiscal 2015. These rates are consistent with the expected long-term rates in place during fiscal 2014.

In August 2014, the Highway and Transportation Funding Act of 2014 (HATFA) was signed into law, which included a provision to extend the interest rate corridors introduced in 2012 under the Moving Ahead for Progress in the 21st Century Act (MAP-21). MAP-21 provided

temporary 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. MAP-21 provided funding relief by allowing pension plans to adjust the interest rates 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 2013 to within 30% for funding periods beginning in 2016. HATFA extended the period of time that the 10% corridor instituted by MAP-21 may be used for funding calculations. Under HATFA, the 10% corridor extends through plan years that begin in 2017 and phases out to a 30% corridor in 2021 and later. HATFA is expected to significantly increase the effective interest rates used in determining funding requirements and could result in a deterioration of the pension plan funded status resulting in much greater funding requirements in the future as well as higher PBGC (Pension Benefit Guaranty Corporation) premiums paid by sponsors of pension plans to protect participants in the event of default by the employer. Management estimates that under the

Table of Contents

provisions of HATFA, the Company may have no minimum funding requirements over the next few years. Although HATFA and MAP-21 allow 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. As a result, the Company expects to contribute approximately $800,000 to its pension plan and $500,000 to its postretirement plan in fiscal 2015. 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.

On October 27, 2014, the Society of Actuaries released the final reports of the pension plan RP-2014 Mortality Tables and the Mortality Improvement Scale MP-2014. The new mortality tables, which will be adopted by the Company for its next pension valuation, extend the assumed life expectancy of participants in defined benefit plans. The estimated impact of the change in assumed mortality would increase the Company s pension liability by 6% to 8% and increase future pension expense.

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

Actuarial Assumption	Change in Assumption	Increase in Pension Cost	Increase in Projected Benefit Obligation
Discount rate	-0.25%	$ 102,000	$ 1,012,000
Rate of return on plan assets	-0.25%	51,000	N/A
Rate of increase in compensation	0.25%	53,000	293,000

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

Actuarial Assumption	Change in Assumption	Increase in Postretirement Benefit Cost	Increase in Accumulated Postretirement Benefit Obligation
Discount rate	-0.25%	$ 30,000	$ 519,000
Rate of return on plan assets	-0.25%	26,000	N/A
Health care cost trend rate	0.25%	71,000	539,000

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. The Company had no commodity or interest rate derivatives outstanding at September 30, 2014.

Table of Contents

MARKET PRICE & DIVIDEND INFORMATION

RGC Resources common stock is listed on the NASDAQ Global 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 long-term capitalization ratios.

YEAR ENDING SEPTEMBER 30	Range of Bid Prices High	Low	Cash Dividends Declared
2014			
First Quarter	**$ 19.98**	**$ 18.10**	**$ 0.185**
Second Quarter	**20.06**	**18.46**	**0.185**
Third Quarter	**19.73**	**19.00**	**0.185**
Fourth Quarter	**20.51**	**19.17**	**0.185**
2013			
First Quarter	$ 19.72	$ 17.51	$ 0.180
Second Quarter	19.40	17.96	0.180
Third Quarter	21.94	18.44	0.180
Fourth Quarter	20.97	17.86	0.180
Special Dividend			1.000

Table of Contents

CAPITALIZATION STATISTICS

YEAR ENDING SEPTEMBER 30	2014	2013	2012	2011	2010
COMMON STOCK					
Shares Issued	**4,720,378**	4,709,326	4,670,567	4,624,682	4,548,864
Earnings Per Share:					
Basic Earnings Per Share	**$ 1.00**	$ 0.91	$ 0.92	$ 1.01	$ 0.98
Diluted Earnings Per Share	**$ 1.00**	$ 0.91	$ 0.92	$ 1.01	$ 0.98
Dividends Paid Per Share (Cash)	**$ 0.74**	$ 1.72	$ 0.70	$ 0.68	$ 0.66
Dividends Paid Out Ratio	**74.0%**	189.0%	76.1%	67.3%	67.3%
CAPITALIZATION RATIOS					
Long-Term Debt, Including Current Maturities	**37.0%**	20.8%	20.4%	36.5%	37.7%
Common Stock And Surplus	**63.0%**	79.2%	79.6%	63.5%	62.3%
Total	**100.0%**	100.0%	100.0%	100.0%	100.0%
Long-Term Debt, Including Current Maturities	**$ 30,500,000**	$ 13,000,000	$ 13,000,000	$ 28,000,000	$ 28,000,000
Common Stock And Surplus	**$ 52,020,847**	$ 49,502,422	$ 50,682,930	$ 48,785,778	$ 46,309,747
Total Capitalization Plus Current Maturities	**$ 82,520,847**	$ 62,502,422	$ 63,682,930	$ 76,785,778	$ 74,309,747

Table of Contents

SUMMARY OF GAS SALES & STATISTICS

YEAR ENDING SEPTEMBER 30	2014	2013	2012	2011	2010
REVENUES:					
Residential Sales	**$ 42,668,037**	$ 36,271,831	$ 32,784,791	$ 40,051,923	$ 42,277,903
Commercial Sales	**25,323,023**	20,597,084	19,164,789	23,463,529	25,166,672
Interruptible Sales	**1,726,749**	1,205,788	1,397,353	1,572,270	573,946
Transportation Gas Sales	**3,157,691**	2,912,550	2,957,344	2,843,115	2,674,151
Inventory Carrying Cost Revenues	**879,381**	937,684	1,236,713	1,395,877	1,546,544
Late Payment Charges	**43,451**	37,407	37,519	44,252	63,949
Miscellaneous Gas Utility Revenue	**67,155**	61,830	79,431	112,654	123,493
Other	**1,150,647**	1,181,492	1,141,747	1,315,251	1,397,256
Total	**$ 75,016,134**	$ 63,205,666	$ 58,799,687	$ 70,798,871	$ 73,823,914
NET INCOME	**$ 4,708,440**	$ 4,262,052	$ 4,296,745	$ 4,653,473	$ 4,445,436
DTH DELIVERED:					
Residential	**4,073,831**	3,821,200	3,036,076	3,866,489	3,910,639
Commercial	**2,932,089**	2,677,583	2,299,760	2,715,998	2,712,692
Interruptible	**305,212**	247,069	286,326	263,851	79,858
Transportation Gas	**2,776,519**	2,663,042	2,695,334	2,698,260	2,610,962
Total	**10,087,651**	9,408,894	8,317,496	9,544,598	9,314,151
HEATING DEGREE DAYS	**4,351**	4,001	3,189	4,091	4,047
NUMBER OF CUSTOMERS:					
Natural Gas					
Residential	**53,410**	53,093	52,836	52,579	51,922
Commercial	**5,108**	5,110	5,072	5,073	5,020
Interruptible and Interruptible Transportation Service	**35**	35	33	32	33
Total	**58,553**	58,238	57,941	57,684	56,975
GAS ACCOUNT (DTH):					
Natural Gas Available	**10,213,316**	9,622,988	8,521,983	9,772,756	9,561,029
Natural Gas Deliveries	**10,087,651**	9,408,894	8,317,496	9,544,598	9,314,151
Storage - LNG	**137,352**	139,875	111,735	114,670	136,972
Company Use And Miscellaneous	**44,486**	50,282	41,620	42,147	47,759
System Loss	**(56,173)**	23,937	51,132	71,341	62,147
Total Gas Available	**10,213,316**	9,622,988	8,521,983	9,772,756	9,561,029
TOTAL ASSETS	**$ 139,320,722**	$ 124,526,701	$ 129,756,338	$ 125,549,049	$ 120,683,316
LONG -TERM OBLIGATIONS	**$ 30,500,000**	$ 13,000,000	$ 13,000,000	$ 13,000,000	$ 28,000,000

Table of Contents

RGC Resources, Inc. and Subsidiaries

Consolidated Financial Statements

for the Years Ended September 30, 2014, 2013

and 2012, and Report of Independent

Registered Public Accounting Firm

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

TABLE OF CONTENTS

	Page
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM	1
CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED SEPTEMBER 30, 2014, 2013 and 2012:	
Consolidated Balance Sheets	2-3
Consolidated Statements of Income	4
Consolidated Statements of Comprehensive Income	5
Consolidated Statements of Stockholders Equity	6
Consolidated Statements of Cash Flows	7
Notes to Consolidated Financial Statements	8-29

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

RGC Resources, Inc.

Roanoke, Virginia

We have audited the accompanying consolidated balance sheets of RGC Resources, Inc. and Subsidiaries (the Company) as of September 30, 2014 and 2013, 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, 2014. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of RGC Resources, Inc. and Subsidiaries as of September 30, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended September 30, 2014, 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, 2014, based on criteria established in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated November 28, 2014 expressed an unqualified opinion on the Company s internal control over financial reporting.

CERTIFIED PUBLIC ACCOUNTANTS

1715 Pratt Drive, Suite 2700

Blacksburg, Virginia

November 28, 2014

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2014 AND 2013

	2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 849,757	$ 2,846,224
Accounts receivable, net	3,730,173	3,729,106
Materials and supplies	893,672	760,781
Gas in storage	11,402,990	10,316,240
Prepaid income taxes	1,144,214	836,966
Deferred income taxes	1,704,320	2,852,073
Under-recovery of gas costs	180,831	
Other	1,104,660	866,646
Total current assets	21,010,617	22,208,036
UTILITY PROPERTY:		
In service	155,360,200	144,388,721
Accumulated depreciation and amortization	(50,645,642)	(48,653,487)
In service, net	104,714,558	95,735,234
Construction work in progress	4,029,019	2,001,315
Utility plant, net	108,743,577	97,736,549
OTHER ASSETS:		
Regulatory assets	9,273,389	4,474,111
Other	293,139	108,005
Total other assets	9,566,528	4,582,116
TOTAL ASSETS	$ 139,320,722	$ 124,526,701

(Continued)

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2014 AND 2013

	2014	2013
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Borrowings under line-of-credit	$ 9,045,050	$
Note payable		15,000,000
Dividends payable	873,326	847,736
Accounts payable	5,367,299	5,723,107
Customer credit balances	1,373,927	1,277,515
Customer deposits	1,492,150	1,476,451
Accrued expenses	2,200,882	2,118,182
Over-recovery of gas costs		1,027,303
Fair value of marked-to-market transactions		1,986,695
Total current liabilities	20,352,634	29,456,989
LONG-TERM DEBT	30,500,000	13,000,000
DEFERRED CREDITS AND OTHER LIABILITIES:		
Asset retirement obligations	4,802,015	4,525,355
Regulatory cost of retirement obligations	8,575,147	8,180,173
Benefit plan liabilities	8,459,436	5,582,073
Deferred income taxes	14,610,643	14,276,596
Deferred investment tax credits		3,093
Total deferred credits and other liabilities	36,447,241	32,567,290
COMMITMENTS AND CONTINGENCIES (Note 9)		
CAPITALIZATION:		
Stockholders Equity:		
Common Stock, $5 par value; authorized 10,000,000 shares; issued and outstanding 4,720,378 and 4,709,326 shares in 2014 and 2013, respectively	23,601,890	23,546,630
Preferred stock, no par; authorized 5,000,000 shares; no shares issued and outstanding in 2014 and 2013		
Capital in excess of par value	8,237,228	8,003,787
Retained earnings	21,321,055	20,103,239
Accumulated other comprehensive loss	(1,139,326)	(2,151,234)
Total stockholders equity	52,020,847	49,502,422
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 139,320,722	$ 124,526,701

(Concluded)

See notes to consolidated financial statements.

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

	2014	2013	2012
OPERATING REVENUES:			
Gas utilities	$ 73,865,487	$ 62,024,174	$ 57,657,940
Other	1,150,647	1,181,492	1,141,747
Total operating revenues	75,016,134	63,205,666	58,799,687
COST OF SALES:			
Gas utilities	45,091,274	34,916,062	31,278,173
Other	587,771	686,713	588,417
Total cost of sales	45,679,045	35,602,775	31,866,590
GROSS MARGIN	29,337,089	27,602,891	26,933,097
OTHER OPERATING EXPENSES:			
Operations and maintenance	13,383,388	12,853,599	12,547,693
General taxes	1,560,386	1,480,746	1,366,680
Depreciation and amortization	4,711,447	4,473,491	4,232,189
Total other operating expenses	19,655,221	18,807,836	18,146,562
OPERATING INCOME	9,681,868	8,795,055	8,786,535
OTHER EXPENSE, net	(206,887)	(60,117)	(19,956)
INTEREST EXPENSE	1,827,001	1,828,099	1,830,885
INCOME BEFORE INCOME TAXES	7,647,980	6,906,839	6,935,694
INCOME TAX EXPENSE	2,939,540	2,644,787	2,638,949
NET INCOME	$ 4,708,440	$ 4,262,052	$ 4,296,745
EARNINGS PER COMMON SHARE:			
Basic	$ 1.00	$ 0.91	$ 0.92
Diluted	$ 1.00	$ 0.91	$ 0.92
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	4,715,478	4,698,727	4,647,439
Diluted	4,716,282	4,698,766	4,650,949

See notes to consolidated financial statements.

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

	2014	2013	2012
NET INCOME	$ 4,708,440	$ 4,262,052	$ 4,296,745
Other comprehensive income, net of tax:			
Interest rate swaps	1,232,546	576,985	245,343
Defined benefit plans	(220,638)	1,221,866	(162,090)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	1,011,908	1,798,851	83,253
COMPREHENSIVE INCOME	$ 5,720,348	$ 6,060,903	$ 4,379,998

See notes to consolidated financial statements.

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
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
Net income			4,262,052		4,262,052
Other comprehensive income				1,798,851	1,798,851
Stock option grants		84,840			84,840
Cash dividends declared ($1.72 per share)			(8,063,327)		(8,063,327)
Issuance of common stock (38,759 shares)	193,795	543,281			737,076
Balance - September 30, 2013	$ 23,546,630	$ 8,003,787	$ 20,103,239	$ (2,151,234)	$ 49,502,422
Net income			4,708,440		4,708,440
Other comprehensive income				1,011,908	1,011,908
Stock option grants		75,310			75,310
Cash dividends declared ($0.74 per share)			(3,490,624)		(3,490,624)
Issuance of common stock (11,052 shares)	55,260	158,131			213,391
Balance - September 30, 2014	$ 23,601,890	$ 8,237,228	$ 21,321,055	$ (1,139,326)	$ 52,020,847

See notes to consolidated financial statements.

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 4,708,440	$ 4,262,052	$ 4,296,745
Adjustments to reconcile net income to net cash provided by operations:			
Depreciation and amortization	4,838,062	4,656,716	4,387,016
Cost of retirement of utility plant, net	(452,834)	(502,587)	(436,120)
Stock option grants	75,310	84,840	
Deferred taxes and investment tax credits	859,788	786,990	2,410,468
Other noncash items, net	38,073	39,186	35,865
Changes in assets and liabilities which provided (used) cash:			
Accounts receivable and customer deposits, net	12,424	(374,682)	(51,234)
Inventories and gas in storage	(1,219,641)	(997,378)	3,394,448
Over/under recovery of gas costs	(1,208,134)	1,714,497	(1,042,670)
Other assets	(306,744)	1,106,590	(418,598)
Accounts payable, customer credit balances and accrued expenses, net	(505,006)	(739,154)	(792,879)
Total adjustments	2,131,298	5,775,018	7,486,296
Net cash provided by operating activities	6,839,738	10,037,070	11,783,041
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for utility property	(14,715,428)	(9,977,433)	(8,683,658)
Proceeds from disposal of utility property	16,858	29,923	32,943
Net cash used in investing activities	(14,698,570)	(9,947,510)	(8,650,715)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds on collection of notes		1,142,770	277,770
Borrowings under line-of-credit	25,363,774	4,354,402	
Repayments under line-of-credit	(16,318,724)	(4,354,402)	
Proceeds from issuance of unsecured notes	30,500,000		
Retirement of note payable	(15,000,000)		
Retirement of long-term debt	(13,000,000)		
Early termination fees	(2,237,961)		
Debt issuance expenses	(193,081)		
Proceeds from issuance of stock	213,391	737,076	774,696
Cash dividends paid	(3,465,034)	(8,033,053)	(3,226,350)
Net cash provided by (used in) financing activities	5,862,365	(6,153,207)	(2,173,884)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,996,467)	(6,063,647)	958,442
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	2,846,224	8,909,871	7,951,429
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 849,757	$ 2,846,224	$ 8,909,871
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the year for:			

Interest	$ 1,966,263	$ 1,803,528	$ 1,783,918
Income taxes	2,387,000	622,076	525,000

See notes to consolidated financial statements.

Table of Contents

RGC RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

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 58,600 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 statements of income and comprehensive income in the period for which FASB ASC No. 980 no longer applied.

Table of Contents

Regulatory assets and liabilities included in the Company s consolidated balance sheets as of September 30, 2014 and 2013 are as follows:

	September 30	
	2014	2013
Regulatory Assets:		
Current Assets:		
Accounts receivable:		
Accrued WNA revenues	$ 143,753	$
Under-recovery of gas costs	180,831	
Other:		
Accrued pension and postretirement medical	394,215	184,063
Utility Property:		
In service:		
Other	11,945	11,945
Other Assets:		
Regulatory assets:		
Premium on early retirement of debt	2,283,744	65,817
Accrued pension and postretirement medical	6,884,812	4,267,211
Other	104,833	141,083
Total regulatory assets	$ 10,004,133	$ 4,670,119
Regulatory Liabilities:		
Current Liabilities:		
Over-recovery of gas costs	$	$ 1,027,303
Accrued expenses:		
Over-recovery of SAVE Plan revenues	187,203	
Deferred Credits and Other Liabilities:		
Asset retirement obligations	4,802,015	4,525,355
Regulatory cost of retirement obligations	8,575,147	8,180,173
Total regulatory liabilities	$ 13,564,365	$ 13,732,831

As of September 30, 2014, the Company had regulatory assets in the amount of $7,527,613 on which the Company did not earn a return during the recovery period. These assets primarily 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 at least every five years. The Company completed its most recent depreciation study and the SCC approved the new depreciation rates in September 2014. The SCC instructed the Company to implement these new rates retroactive to October 1, 2013. As a result of the new rates, the composite weighted-average depreciation rate declined slightly to 3.25% for the year ended September 30, 2014 as compared to 3.35% and 3.34% for the fiscal years ended September 30, 2013 and 2012, respectively. The change in depreciation rates is considered a change in accounting estimate and is recorded in the period in which the Company received approval from the SCC. The effect of this change in estimate was to reduce depreciation expense by $126,875 and increase net income by $78,713 and earnings per share by $0.02 for the year ended September 30, 2014.

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.

Table of Contents

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 have 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 evacuating 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. In both 2014 and 2013, 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	
	2014	**2013**
Beginning balance	$ 4,525,355	$ 4,251,295
Liabilities incurred	74,276	75,312
Liabilities settled	(165,845)	(194,602)
Accretion	258,763	249,293
Revisions to estimated cash flows	109,466	144,057
Ending balance	$ 4,802,015	$ 4,525,355

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, 2014, 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		
	2014	**2013**	**2012**
Beginning balance	$ 68,539	$ 65,219	$ 66,058
Provision for doubtful accounts	148,881	85,033	11,588
Recoveries of accounts written off	136,369	122,432	134,331
Accounts written off	(283,042)	(204,145)	(146,758)
Ending balance	$ 70,747	$ 68,539	$ 65,219

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. Trade receivables are the Company s one primary type of financing receivables, resulting from the sale of natural gas and other services to its customers. These receivable are short-term in nature with a provision for uncollectible balances included in the financial statements.

Table of Contents

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, 2014 and 2013 were $1,071,128 and $1,056,253, 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.

Table of Contents

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		
	2014	2013	2012
Net Income	$ 4,708,440	$ 4,262,052	$ 4,296,745
Weighted-average common shares	4,715,478	4,698,727	4,647,439
Effect of dilutive securities:			
Options to purchase common stock	804	39	3,510
Diluted average common shares	4,716,282	4,698,766	4,650,949
Earnings Per Share of Common Stock:			
Basic	$ 1.00	$ 0.91	$ 0.92
Diluted	$ 1.00	$ 0.91	$ 0.92

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 all 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, 2014 and 2013, the Company had no outstanding derivative instruments for the purchase of natural gas.

The Company also had two interest rate swaps that essentially converted its variable interest rate notes to fixed rate debt instruments. Both swaps were terminated in September 2014 as part of the Company s debt refinancing as described in more detail in Note 4. These swaps qualified 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.

Table of Contents

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, 2014 and 2013:

	September 30	
	2014	**2013**
Derivatives designated as hedging instruments:		
Interest rate swaps	$	$ 1,986,695
Total derivatives designated as hedging instruments	$	$ 1,986,695

See Note 10 for additional information on fair value.

Table of Contents

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, 2014:			
Interest rate swaps:			
Unrealized losses	$ (58,800)	$ 22,321	$ (36,479)
Transfer of realized losses to interest expense	926,262	(351,609)	574,653
Transfer of realized losses to regulatory asset	1,119,233	(424,861)	694,372
Net unrealized losses on interest rate swaps	1,986,695	(754,149)	1,232,546
Defined benefit plans:			
Net loss arising during period	(397,714)	151,131	(246,583)
Amortization of actuarial losses	41,846	(15,901)	25,945
Net defined benefit plans	(355,868)	135,230	(220,638)
Other comprehensive income	$ 1,630,827	$ (618,919)	$ 1,011,908
Year Ended September 30, 2013:			
Interest rate swaps:			
Unrealized losses	$ (20,479)	$ 7,774	$ (12,705)
Transfer of realized losses to interest expense	950,501	(360,811)	589,690
Net unrealized losses on interest rate swaps	930,022	(353,037)	576,985
Defined benefit plans:			
Net gain arising during period	1,714,890	(651,659)	1,063,231
Amortization of actuarial losses	219,890	(83,558)	136,332
Amortization of transition obligation	35,972	(13,669)	22,303
Net defined benefit plans	1,970,752	(748,886)	1,221,866
Other comprehensive income	$ 2,900,774	$ (1,101,923)	$ 1,798,851
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 unrealized losses on 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

The amortization of actuarial losses and transition obligation is included as components of net periodic pension and postretirement benefit costs and is included in operations and maintenance expense.

Table of Contents

Composition of Accumulated Other Comprehensive Income (Loss)

	Interest Rate Swaps	Defined Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Balance September 30, 2011	$ (2,054,874)	$ (1,978,464)	$ (4,033,338)
Other comprehensive income (loss)	245,343	(162,090)	83,253
Balance September 30, 2012	(1,809,531)	(2,140,554)	(3,950,085)
Other comprehensive income (loss)	576,985	1,221,866	1,798,851
Balance September 30, 2013	(1,232,546)	(918,688)	(2,151,234)
Other comprehensive income (loss)	1,232,546	(220,638)	1,011,908
Balance September 30, 2014	$	$ (1,139,326)	$ (1,139,326)

Recently Adopted Accounting Standards 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. In February 2013, the FASB issued additional guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. Under the new provisions, an entity must present the effects on the line items of net income of significant amounts reclassified out of accumulated other comprehensive income. The disclosures required under this guidance are provided above.

Recently Issued Accounting Standards In May 2014, the FASB issued guidance under FASB ASC No. 606 *Revenue from Contracts with Customers* that affects any entity that enters into contracts with customers for the transfer of goods or services or transfer of non-financial assets. This guidance will supersede the revenue recognition requirements in Topic 605, *Revenue Recognition,* and most industry-specific guidance. The core principle of the new guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve that core principle, an entity should apply these steps: (1) identify the contract with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when, or as, the entity satisfies the performance obligation. The new guidance is effective for the Company for the annual reporting period ended September 30, 2018 and interim periods within that annual period. Early application is not permitted. Management has not completed its evaluation of the new guidance. However, the Company does not currently expect the new guidance to have a material effect on its financial position, results of operations or cash flows.

Other accounting standards that have been issued or proposed by the FASB or other standard setting bodies are not 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, 2013 the Company placed into effect new base rates, subject to refund, that would provide for approximately $1,664,000 in additional non-gas revenues. On May 9, 2014, the SCC issued a final order granting the Company a rate award in the amount of $887,062 in

additional non-gas revenues while maintaining a 9.75% authorized return on equity. During June 2014, 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.

In connection with the order approving the non-gas rate award, the SCC also approved a change to the Company s weather normalization adjustment mechanism (WNA). Previously, the WNA provided for a weather band of 3%

Table of Contents

above or below the 30-year temperature average whereby the Company would recover from its customers the lost margin (excluding gas costs) from the impact of weather that was more than 3% warmer than the 30-year average or refund to customers the excess earned from weather that was more than 3% colder than the 30-year average. Effective with the WNA period that began April 1, 2014, the SCC removed the 3% weather band from the WNA calculation. This change will now result in either a recovery or refund of revenues due to weather variations from the 30-year average.

On June 4, 2014, the Company filed an application with the SCC requesting approval to extend its existing authority to incur short-term indebtedness of up to $30,000,000 and to issue up to $60,000,000 in long-term securities. The short-term indebtedness authority will allow the Company to continue to access its line-of-credit to provide seasonal funding of its working capital needs as well as provide temporary bridge financing for its capital expenditures. The application also included the Company s plan to refinance its outstanding debt obligations with lower interest rate debt and provide the Company with future long-term financing options. On June 25, 2014, the SCC issued an order granting the approval of the Company s request including its plan to refinance its then outstanding debt obligations. Notes 3 and 4 provide additional information regarding the refinancing of Company debt.

On June 10, 2014, the Company filed an updated depreciation study with the SCC as required at least every five years. The depreciation study, which is based on average remaining service life, resulted in a small reduction in the overall composite weighted average depreciation rate from 3.35% in fiscal 2013 to 3.25% in fiscal 2014. The SCC approved the depreciation study filing and instructed the Company to implement the new rates effective as of October 1, 2013. As a result, the Company recorded the full effect of the change in depreciation rates for the fiscal year ended September 30, 2014 in the Company s fourth quarter results of operations. The effect of the change in depreciation rates on the Company s Consolidated Statement of Income is included in Note 1.

3. SHORT-TERM DEBT

The Company has available an unsecured line-of-credit with a bank which will expire March 31, 2015. 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, 2014	$ 15,000,000
October 24, 2014	19,000,000
February 1, 2015	16,000,000
March 1, 2015	12,000,000

A summary of the line-of-credit follows:

	September 30		
	2014	2013	2012
Line-of-credit at year-end	$ 15,000,000	$ 5,000,000	$ 3,000,000
Outstanding balance at year-end	9,045,050		
Highest month-end balance outstanding	9,045,050	1,414,955	
Average daily balance	1,340,833	80,593	
Average rate of interest during year on outstanding balances	1.16%	1.21%	%
Interest rate at year-end	1.16%	1.18%	1.22%
Interest rate on unused line-of-credit	0.15%	0.15%	0.15%

On September 18, 2014, the Company refinanced its unsecured note in the principal amount of $15,000,000. This note along with its corresponding interest rate swap were included as part of the debt refinancing as described in Note 4. The effective rate of interest on the combined note and interest rate swap was 5.74%.

Table of Contents

4. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30	
	2014	2013
Unsecured senior notes payable, at 4.26%, due on September 18, 2034	$ 30,500,000	$
Unsecured note payable, with variable interest rate based on three month LIBOR plus 125 basis point spread		5,000,000
Unsecured senior note payable, at 7.66%		8,000,000
Total long-term debt	30,500,000	13,000,000
Less current maturities		
Total long-term debt	$ 30,500,000	$ 13,000,000

On September 18, 2014, the Company issued unsecured senior notes in the aggregate principal amount of $30,500,000 with a fixed interest rate of 4.26% per annum. The proceeds from these notes were used to retire, prior to original maturity, the $5,000,000 unsecured note payable and corresponding interest rate swap with an effective interest rate of 5.79%, the $8,000,000 unsecured note payable with a fixed interest rate of 7.66% and the $15,000,000 short-term note payable and corresponding interest rate swap with an effective interest rate of 5.74%. In exchange for retiring the notes and related swap instruments, the Company paid $2,237,961 in early termination fees. These termination fees have been deferred in accordance with regulatory accounting treatment and will be amortized over the term of the new notes.

The new obligations contain various provisions, including two financial covenants. First, total long-term debt, including current maturities, shall not exceed 65% of total capitalization. Second, the Company shall not allow priority indebtedness to exceed 15% of total assets. As compared to the prior debt agreements, the Company no longer has covenants restricting the payment of dividends, except to the extent such dividend declaration and payment would cause the total long-term debt to exceed 65% of total capitalization.

The aggregate annual maturities of long-term debt for the next five years ending after September 30, 2014 are as follows:

Year Ending September 30	Maturities
2015	$
2016	
2017	
2018	
2019	
Thereafter	30,500,000
Total	$ 30,500,000

5. INCOME TAXES

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

	Years Ended September 30		
	2014	2013	2012
Current income taxes:			
Federal	$ 1,789,294	$ 1,404,450	$ (38,608)
State	290,458	453,347	232,270

Total current income taxes	2,079,752	1,857,797	193,662
Deferred income taxes:			
Federal	687,417	829,080	2,269,921
State	175,464	(33,051)	184,405
Total deferred income taxes	862,881	796,029	2,454,326
Amortization of investment tax credits	(3,093)	(9,039)	(9,039)
Total income tax expense	$ 2,939,540	$ 2,644,787	$ 2,638,949

Table of Contents

Income tax expense for the years ended September 30, 2014, 2013 and 2012 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		
	2014	2013	2012
Income before income taxes	$ 7,647,980	$ 6,906,839	$ 6,935,694
Income tax expense computed at the federal statutory rate	$ 2,600,313	$ 2,348,325	$ 2,358,136
State income taxes, net of federal income tax benefit	307,509	277,395	275,005
Amortization of investment tax credits	(3,093)	(9,039)	(9,039)
Other, net	34,811	28,106	14,847
Total income tax expense	$ 2,939,540	$ 2,644,787	$ 2,638,949

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

	September 30	
	2014	2013
Deferred tax assets:		
Allowance for uncollectibles	$ 26,855	$ 26,017
Accrued pension and postretirement medical benefits	2,077,409	1,997,001
Accrued vacation	230,842	229,669
Over-recovery of gas costs		389,965
Costs of gas held in storage	973,651	1,055,768
Accrued gas costs	36,305	8,999
Deferred compensation	579,451	493,088
Interest rate swap		754,149
Other	295,654	214,172
Total gross deferred tax assets	4,220,167	5,168,828
Deferred tax liabilities:		
Utility plant	17,057,847	16,593,351
Under-recovery of gas costs	68,643	
Total gross deferred tax liabilities	17,126,490	16,593,351
Net deferred tax liability	$ 12,906,323	$ 11,424,523

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, 2011 are no longer subject to examination.

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 5 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 10 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.

Table of Contents

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 other 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	
	2014	2013	2014	2013
Accumulated benefit obligation	$ 20,697,734	$ 17,909,824	$ 14,983,169	$ 13,028,628
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 21,468,769	$ 23,570,451	$ 13,028,628	$ 13,707,309
Service cost	553,291	634,892	168,634	213,131
Interest cost	1,020,302	946,247	602,684	531,845
Actuarial (gain) loss	2,199,697	(3,105,394)	1,673,552	(939,539)
Benefit payments, net of retiree contributions	(605,364)	(577,427)	(490,329)	(484,118)
Benefit obligation at end of year	$ 24,636,695	$ 21,468,769	$ 14,983,169	$ 13,028,628
Change in fair value of plan assets:				
Fair value of plan assets at beginning of year	$ 18,801,262	$ 16,063,381	$ 10,114,062	$ 8,673,128
Actual return on plan assets, net of taxes	1,750,033	2,215,308	522,516	1,075,052
Employer contributions	568,248	1,100,000	500,000	850,000
Benefit payments, net of retiree contributions	(605,364)	(577,427)	(490,329)	(484,118)
Fair value of plan assets at end of year	$ 20,514,179	$ 18,801,262	$ 10,646,249	$ 10,114,062
Funded status	$ (4,122,516)	$ (2,667,507)	$ (4,336,920)	$ (2,914,566)
Amounts recognized in the balance sheets consist of:				
Noncurrent liabilities	$ (4,122,516)	$ (2,667,507)	$ (4,336,920)	$ (2,914,566)
Amounts recognized in accumulated other comprehensive loss:				
Transition obligation, net of tax	$	$	$	$
Net actuarial loss, net of tax	616,352	591,195	522,974	327,493
Total amounts included in other comprehensive loss, net of tax	$ 616,352	$ 591,195	$ 522,974	$ 327,493
Amounts deferred to a regulatory asset:				
Transition obligation	$	$	$	$
Net actuarial loss	4,166,900	2,581,852	3,112,127	1,869,422
Amounts recognized as regulatory assets	$ 4,166,900	$ 2,581,852	$ 3,112,127	$ 1,869,422

The Company expects that approximately $60,000 before tax, of accumulated other comprehensive loss will be recognized as a portion of net periodic benefit costs in fiscal 2015 and approximately $394,000 of amounts deferred as regulatory assets will be amortized and recognized in

net periodic benefit costs in fiscal 2015.

The Company amortized the unrecognized transition obligation over 20 years ending in June 2013.

Table of Contents

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 2014, 2013 and 2012.

	Pension Plan			Postretirement Plan		
	2014	2013	2012	2014	2013	2012
Assumptions used to determine benefit obligations:						
Discount rate	4.22%	4.82%	4.06%	4.10%	4.73%	3.95%
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	4.82%	4.06%	5.04%	4.73%	3.95%	4.96%
Expected long-term rate of return on plan assets	7.00%	7.25%	7.25%	4.92%	5.11%	5.11%
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		
	2014	2013	2012	2014	2013	2012
Service cost	$ 553,291	$ 634,892	$ 521,701	$ 168,634	$ 213,131	$ 195,777
Interest cost	1,020,302	946,247	953,197	602,684	531,845	592,359
Expected return on plan assets	(1,312,354)	(1,184,787)	(959,178)	(496,476)	(452,383)	(367,359)
Amortization of unrecognized transition obligation					141,671	188,892
Recognized loss	136,394	578,263	475,414	89,515	241,747	239,387
Net periodic benefit cost	$ 397,633	$ 974,615	$ 991,134	$ 364,357	$ 676,011	$ 849,056

The assumed health care cost trend rates used in measuring the accumulated benefit obligation for the postretirement medical plan as of September 30, 2014, 2013 and 2012 are presented below:

	Pre 65			Post 65		
	2014	2013	2012	2014	2013	2012
Health care cost trend rate assumed for next year	8.50%	9.00%	9.00%	5.00%	5.00%	6.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2021	2021	2016	2014	2013	2013

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	$ 128,000	$ (104,000)
Effect on accumulated postretirement benefit obligation	2,155,000	(1,769,000)

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.

Table of Contents

The Company s target and actual asset allocation in the pension and postretirement benefit plans as of September 30, 2014 and 2013 were:

	Pension Plan			Postretirement Plan		
	Target	2014	2013	Target	2014	2013
Asset category:						
Equity securities	60%	60%	63%	50%	55%	62%
Debt securities	40%	39%	37%	50%	44%	36%
Cash	%	1%	%	%	1%	1%
Other	%	%	%	%	%	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, 2014			
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 182,644	$ 182,644	$	$
Common and Collective Trust and				
Pooled Funds:				
Bonds				
Domestic Fixed Income	1,455,153		1,455,153	
Equities				
Domestic Large Cap Growth	2,079,566		2,079,566	
Domestic Large Cap Value	3,295,144		3,295,144	
Domestic Small/Mid Cap Core	1,850,340		1,850,340	
Foreign Large Cap Value	1,641,619		1,641,619	
Mutual Funds:				
Bonds				
Domestic Fixed Income	6,289,437		6,289,437	
Foreign Fixed Income	204,747		204,747	
Equities				
Domestic Large Cap Growth	2,088,528		2,088,528	
Foreign Large Cap Value	608,787		608,787	
Foreign Large Cap Core	818,214		818,214	
Total	$ 20,514,179	$ 182,644	$ 20,331,535	$

Table of Contents

	Defined Benefit Pension Plan Fair Value Measurements - September 30, 2013			
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 66,084	$ 66,084	$	$
Common and Collective Trust and				
Pooled Funds:				
Bonds				
Domestic Fixed Income	2,043,005		2,043,005	
Equities				
Domestic Large Cap Growth	2,769,927		2,769,927	
Domestic Large Cap Value	3,430,746		3,430,746	
Domestic Small/Mid Cap Core	1,770,381		1,770,381	
Mutual Funds:				
Bonds				
Domestic Fixed Income	4,326,814		4,326,814	
Foreign Fixed Income	597,799		597,799	
Equities				
Domestic Large Cap Growth	2,115,392		2,115,392	
Foreign Large Cap Value	698,554		698,554	
Foreign Large Cap Core	982,560		982,560	
Total	$ 18,801,262	$ 66,084	$ 18,735,178	$

	Postretirement Benefit Plan Fair Value Measurements - September 30, 2014			
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 116,173	$ 116,173	$	$
Mutual Funds				
Bonds				
Domestic Fixed Income	4,658,299		4,658,299	
Foreign Fixed Income	101,904		101,904	
Equities				
Domestic Large Cap Growth	1,789,381		1,789,381	
Domestic Large Cap Value	1,759,740		1,759,740	
Domestic Small/Mid Cap Growth	400,898		400,898	
Domestic Small/Mid Cap Value	396,537		396,537	
Domestic Small/Mid Cap Core	37,741		37,741	
Foreign Large Cap Value	941,153		941,153	
Foreign Large Cap Core	394,769		394,769	
Other	49,654		49,654	
Total	$ 10,646,249	$ 116,173	$ 10,530,076	$

Table of Contents

	Postretirement Benefit Plan Fair Value Measurements - September 30, 2013			
	Fair Value	Level 1	Level 2	Level 3
Asset Class:				
Cash	$ 124,350	$ 124,350	$	$
Mutual Funds				
Bonds				
Domestic Fixed Income	3,448,416		3,448,416	
Foreign Fixed Income	214,528		214,528	
Equities				
Domestic Large Cap Growth	2,277,582		2,277,582	
Domestic Large Cap Value	1,671,591		1,671,591	
Domestic Small/Mid Cap Growth	480,438		480,438	
Domestic Small/Mid Cap Value	467,661		467,661	
Domestic Small/Mid Cap Core	35,809		35,809	
Foreign Large Cap Growth	420,153		420,153	
Foreign Large Cap Value	386,684		386,684	
Foreign Large Cap Core	534,747		534,747	
Other	52,103		52,103	
Total	$ 10,114,062	$ 124,350	$ 9,989,712	$

Each mutual fund has been categorized based on its primary investment strategy.

The Company expects to contribute $800,000 to its pension plan and $500,000 to its postretirement benefit plan in fiscal 2015.

The following table reflects expected future benefit payments:

Fiscal year ending September 30	Pension Plan	Postretirement Plan
2015	$ 658,958	$ 700,411
2016	663,482	706,182
2017	697,730	701,764
2018	765,358	702,568
2019	806,282	718,275
2020-2024	5,802,914	4,143,874

The Company also sponsors a defined contribution plan (401k Plan) covering all employees who elect to participate. Employees may contribute from 1% to 50% of their annual compensation to the 401k Plan, limited to a maximum annual amount as set periodically by the Internal Revenue Service. The Company matches 100% of the participant s first 4% of contributions and 50% on the next 2% of contributions. Company matching contributions were $330,241, $306,382 and $295,584 for 2014, 2013 and 2012, respectively.

7. COMMON STOCK OPTIONS

The Company s stockholders approved the RGC Resources, Inc. Key Employee Stock Option Plan (KESOP). The KESOP provides for the issuance of common stock options to officers and certain other full-time salaried employees to acquire shares of the Company s common stock. As of September 30, 2014, the number of shares available for future grants was 66,000.

FASB ASC No. 718 - *Compensation-Stock Compensation* requires that compensation expense be recognized for the issuance of equity instruments to employees. During the fiscal years ended 2014 and 2013, the Board approved stock option grants to certain officers. As required by the KESOP, each option s exercise price per share equaled the fair value of the Company s common stock on the grant date. Pursuant to the Plan, the options vest over a six-month period and are exercisable over a ten-year period from the date of issuance.

Table of Contents

As the Company s stock options are not traded on the open market, the fair value of each grant is estimated on the date of grant using the Black-Scholes option pricing model including the following assumptions:

	Years Ended September 30,		
	2014	2013	2012
Expected volatility	35.01%	34.75%	N/A
Expected dividends	4.21%	4.32%	N/A
Expected exercise term (years)	7.00	7.00	N/A
Risk-free interest rate	2.23%	1.23%	N/A

The underlying methods regarding each assumption are as follows:

Expected volatility is based on the historical volatilities of the daily closing price of the Company s common stock.

Expected dividend rate is based on historical dividend payout trends.

Expected exercise term is based on the average time historical option grants were outstanding before being exercised.

Risk-free interest rate is based on the 7-year Treasury rate on the date of option grant.

No ***forfeitures*** are assumed to occur.

Table of Contents

Stock option transactions under the Company s plans for the years ended September 30, 2014, 2013 and 2012 are summarized below:

	Number of Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Terms (years)	Aggregate Intrinsic Value
Options outstanding, September 30, 2011	11,000	$ 9.05	1.2	$ 105,600
Options granted				
Options exercised	(11,000)	9.05		
Options expired				
Options forfeited				
Options outstanding, September 30, 2012			0.0	
Options granted	21,000	19.01		
Options exercised				
Options expired				
Options forfeited				
Options outstanding, September 30, 2013	21,000	19.01	9.5	5,229
Options granted	17,000	18.95		
Options exercised				
Options expired				
Options forfeited				
Options outstanding, September 30, 2014	38,000	$ 18.98	8.8	$ 34,840
Vested and exercisable at September 30, 2014	38,000	$ 18.98	8.8	$ 34,840

The weighted-average grant-date fair value of options granted during the years ended September 30, 2014 and 2013 was $4.43 and $4.04. The intrinsic value of the options exercised during fiscal 2012 was $91,721. The Company recognized $75,310 and $84,840 in stock option expense in fiscal 2014 and 2013.

The Company received $99,550 from the exercise of options in 2012. No options were exercised in 2013 or 2014.

Table of Contents

8. OTHER STOCK PLANS

Dividend Reinvestment and Stock Purchase Plan

The Company offers a Dividend Reinvestment and Stock Purchase Plan (DRIP) to shareholders of record for the reinvestment of dividends and the purchase of additional investments of up to $40,000 per year in shares of common stock of the Company. Under the DRIP plan, the Company issued 7, 24,905 and 25,077 shares in 2014, 2013 and 2012, respectively. As of September 30, 2014, the Company had 366,808 shares of stock available for issuance under the DRIP Plan.

Restricted Stock Plan

The Board of Directors of the Company implemented the Restricted Stock Plan for Outside Directors (Plan) effective January 27, 1997. Under the Plan, a minimum of 40% of the monthly retainer fee paid to each non-employee director of Resources is paid in shares of common stock (Restricted Stock). The number of shares of Restricted Stock is calculated each month based on the closing sales price of Resources common stock on the NASDAQ Global Market on the first business day of the month. The Restricted Stock issued under this Plan vests only in the case of a participant s death, disability, retirement, or in the event of a change in control of Resources. The Restricted Stock may not be sold, transferred, assigned or pledged by the participant until the shares have vested under the terms of this Plan. The shares of Restricted Stock will be forfeited to Resources by a participant s voluntary resignation during his or her term on the Board or removal for cause as a director.

The Company assumes all directors will complete their term and there will be no forfeiture of the Restricted Stock. Since the inception of the Plan, no director has forfeited any shares of Restricted Stock. The Company recognizes as compensation the market value of the Restricted Stock in the period it is issued.

The following table reflects the director compensation activity pursuant to the Restricted Stock Plan:

	2014		2013		2012	
	Shares	Weighted-Average Fair Value on Date of Grant	Shares	Weighted-Average Fair Value on Date of Grant	Shares	Weighted-Average Fair Value on Date of Grant
Beginning of year balance	59,064	$ 13.97	54,011	$ 13.51	61,955	$ 12.81
Granted	3,780	19.37	5,053	18.93	5,327	18.23
Vested					(13,271)	12.16
Forfeited						
End of year balance	62,844	$ 14.29	59,064	$ 13.97	54,011	$ 13.51

The fair market value of the Restricted Stock issued as compensation during fiscal 2014, 2013 and 2012 was $73,200, $95,667 and $97,133. The fair market value of the Restricted Stock vested during fiscal 2014, 2013 and 2012 is $0, $0, and $161,338, respectively.

As of September 30, 2014, the Company had 78,318 shares available for issuance under the Restricted Stock Plan. No shares of Restricted Stock were forfeited to Resources by a director during the fiscal year ended September 30, 2014.

Stock Bonus Plan

Under the Stock Bonus Plan, executive officers are encouraged to own a position in the Company s common stock of at least 50% of the value of their annual salary. To promote this policy, the Plan provides that all officers with stock ownership positions below 50% of the value of their annual salaries must, unless approved by the Committee, receive no less than 50% of any performance bonus in the form of Company common stock. Shares from the Stock Bonus Plan may also be issued to certain employees and management personnel in recognition of their performance and service. Under the Stock Bonus Plan, the Company issued 4,098, 4,022 and 1,640 shares valued at $78,841, $72,580 and $30,763, respectively, in 2014, 2013 and 2012. As of September 30, 2014 the Company had 10,905 shares of stock available for issuance under the Stock Bonus Plan.

Table of Contents

9. COMMITMENTS AND CONTINGENCIES

Long-Term Contracts

Due to the nature of the natural gas distribution business, the Company enters into agreements with both suppliers and pipelines to contract for natural gas commodity purchases, storage capacity and pipeline delivery capacity. The Company obtains most of its regulated natural gas supply through an asset management contract between Roanoke Gas and a third party asset manager. The Company utilizes an asset manager to optimize the use of its transportation, storage rights, and gas supply inventories which helps to ensure a secure and reliable source of natural gas. Effective November 1, 2013, the Company entered into a new asset management agreement with a different asset manager. Under the asset management contract, the Company has designated the asset manager as agent for their storage capacity and all gas balances in storage. The Company retains ownership of gas in storage. Under provisions of this contract, the Company is obligated to purchase its winter storage requirements from the asset manager during the spring and summer injection periods at market price. The table below details the volumetric obligations as of September 30, 2014 for the remainder of the contract period.

Year	Natural Gas Contracts (In Decatherms)
2014-2015	2,071,061
2015-2016	2,071,061
2016-2017	295,866
Total	4,437,988

The Company also has contracts for pipeline and storage capacity which extend for various periods. These capacity costs and related fees are valued at tariff rates in place as of September 30, 2014. These rates may increase or decrease in the future based upon rate filings and rate orders granting a rate change to the pipeline or storage operator. The Company expended approximately $44,884,000, $35,348,000 and $26,794,000 under the asset management, pipeline and storage contracts for Roanoke Gas in fiscal years 2014, 2013 and 2012, respectively. The table below details the pipeline and storage capacity obligations as of September 30, 2014 for the remainder of the contract period.

Year	Pipeline and Storage Capacity
2014-2015	$ 11,383,418
2015-2016	11,359,785
2016-2017	9,971,107
2017-2018	7,764,268
2018-2019	6,139,313
Thereafter	2,411,198
Total	$ 49,029,089

Other Contracts

The Company maintains other agreements in the ordinary course of business covering various lease, maintenance, equipment and service contracts. These agreements currently extend through December 2031 and are not material to the Company.

Legal

From time to time, the Company may become involved in litigation or claims arising out of its operations in the normal course of business. Management currently believes the amount of ultimate liability, if any, with respect to these actions will not materially affect the Company s financial position, results of operations, or liquidity.

Environmental Matters

Both Roanoke Gas Company and a previously owned gas subsidiary operated manufactured gas plants (MGPs) as a source of fuel for lighting and heating until the early 1950 s. A by-product of operating MGPs was coal tar, and the potential exists for on-site tar waste contaminants at the former plant sites. While the Company does not currently

Table of Contents

recognize any commitments or contingencies related to environmental costs at either site, should the Company ever be required to remediate either site, it will pursue all prudent and reasonable means to recover any related costs, including the use of insurance claims and regulatory approval for rate case recognition of expenses associated with any work required.

10. FAIR VALUE MEASUREMENTS

The following table summarizes the Company s financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements by level within the fair value hierarchy as defined in Note 1 as of September 30, 2014 and 2013, respectively:

		Fair Value Measurements - September 30, 2014		
	Fair Value	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Liabilities:				
Natural gas purchases	$ 795,019	$	$ 795,019	$
Total	$ 795,019	$	$ 795,019	$

		Fair Value Measurements - September 30, 2013		
	Fair Value	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Liabilities:				
Natural gas purchases	$ 1,177,521	$	$ 1,177,521	$
Interest rate swaps	1,986,695		1,986,695	
Total	$ 3,164,216	$	$ 3,164,216	$

Under the asset management contract, a timing difference can exist between the payment for natural gas purchases and the actual receipt of such purchases. Payments are made based on a predetermined monthly volume with the price based on the weighted average first of the month index prices corresponding to the month of the scheduled payment. At September 30, 2014 and 2013, the Company had recorded in accounts payable the estimated fair value of the liability determined on the corresponding first of month index prices for which the liability was expected to be settled.

The fair value of the interest rate swaps, included in the line item Fair value of marked-to-market transactions , is determined by using the counterparty s proprietary models and certain assumptions regarding past, present and future market conditions.

The Company s nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis consist of its asset retirement obligations. The asset retirement obligations are measured at fair value at initial recognition based on expected future cash flows to settle the obligation.

The carrying value of cash and cash equivalents, accounts receivable, borrowings under line-of-credit, accounts payable (with the exception of the timing difference under the asset management contract), customer credit balances and customer deposits is a reasonable estimate of fair value due to the short-term nature of these financial instruments. The following table summarizes the fair value of the Company s financial assets and liabilities that are not adjusted to fair value in the financial statements as of September 30, 2014 and 2013.

		Fair Value Measurements - September 30, 2014		
	Carrying Amount	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Liabilities:				
Long-term debt	$ 30,500,000	$	$	$ 30,622,664
Total	$ 30,500,000	$	$	$ 30,622,664

Table of Contents

		Fair Value Measurements - September 30, 2013		
	Carrying Amount	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Liabilities:				
Note payable	$ 15,000,000	$	$	$ 14,976,818
Long-term debt	13,000,000			13,762,952
Total	$ 28,000,000	$	$	$ 28,739,770

Note payable is included in current liabilities at September 30, 2013.

The fair value of the note payable was estimated by using the interest rate under the Company s line-of-credit agreement which renewed at the same time as the term note. Both the line-of-credit and term note have a term of one year. The fair value of long-term debt is estimated by discounting the future cash flows of the fixed rate debt based on the underlying 20-year Treasury rate and estimated credit spread for the note issued in 2014 and rates extrapolated based on market conditions for the prior year. The variable rate long-term debt and note payable had interest rate swaps that effectively convert such debt to a fixed rate. The values of the swap agreements are included in the second table above.

FASB ASC 825 *Financial Instruments* requires disclosures regarding concentrations of credit risk from financial instruments. Cash equivalents are investments in high-grade, short-term securities (original maturity less than three months), placed with financially sound institutions. Accounts receivable are from a diverse group of customers including individuals and small and large companies in various industries. The Company maintains certain credit standards with its customers and requires a customer deposit if such evaluation warrants.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly financial data for the years ended September 30, 2014 and 2013 is summarized as follows:

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 20,011,194	$ 32,699,965	$ 12,024,817	$ 10,280,158
Gross margin	$ 8,202,992	$ 10,161,125	$ 5,721,551	$ 5,251,421
Operating income	$ 3,272,646	$ 5,121,022	$ 940,691	$ 347,509
Net income (loss)	$ 1,722,788	$ 2,846,795	$ 283,194	$ (144,337)
Earnings per share of common stock:				
Basic	$ 0.37	$ 0.60	$ 0.06	$ (0.03)
Diluted	$ 0.37	$ 0.60	$ 0.06	$ (0.03)

2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenues	$ 18,746,592	$ 24,175,638	$ 11,037,308	$ 9,246,128
Gross margin	$ 7,936,483	$ 9,585,727	$ 5,229,027	$ 4,851,654

Operating income	$ 2,950,091	$ 4,813,348	$ 645,821	$ 385,795
Net income (loss)	$ 1,554,153	$ 2,698,707	$ 110,103	$ (100,911)
Earnings per share of common stock:				
Basic	$ 0.33	$ 0.57	$ 0.02	$ (0.02)
Diluted	$ 0.33	$ 0.57	$ 0.02	$ (0.02)

12. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date the financial statements were issued. There were no items not otherwise disclosed which would have materially impacted the Company s consolidated financial statements.

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Table of Contents

CORPORATE INFORMATION

CORPORATE OFFICE

RGC Resources, Inc.

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P.O. Box 13007

Roanoke, VA 24030

Tel: (540) 777-4GAS (4427)

Fax: (540) 777-2636

INDEPENDENT REGISTERED ACCOUNTING FIRM

Brown Edwards & Company, L.L.P.

1715 Pratt Drive, Suite 2700

Blacksburg, VA 24060

COMMON STOCK TRANSFER AGENT, REGISTRAR, DIVIDEND DISBURSING

American Stock Transfer & Trust Company, LLC

6201 15th Avenue

Brooklyn, NY 11219

(866) 673-8053

COMMON STOCK

RGC Resources common stock is listed on the NASDAQ Global Market under the trading symbol **RGCO**.

DIRECT DEPOSIT OF DIVIDENDS AND SAFEKEEPING OF STOCK CERTIFICATES

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

10-K REPORT

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

Dale P. Lee

Vice President and Secretary

RGC Resources, Inc.

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

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

SHAREHOLDER INQUIRIES

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

RGC Resources, Inc.

Vice President and Secretary

P.O. Box 13007

Roanoke, VA 24030

(540) 777-3846

FINANCIAL INQUIRIES

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

RGC Resources, Inc.

Vice President and Secretary

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

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Table of Contents