Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(n)
Sponsoring Witness: W. Steven Seelye

Description of Filing Requirement:

A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case a reference to that case's number and style will be sufficient.

Response:

A copy of Delta's most recent depreciation study is included in Volume III with the testimony of William Steven Seelye as Seelye Exhibit 11.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(o)
Sponsoring Witness: Matthew Wesolosky

Description of Filing Requirement:

A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.

Response:

See attached.

Delta Natural Gas Company
List of Software, Programs and Models Used

Software	Model	System Requirements	Purpose
Microsoft Word	2007	Windows XP - SP2 or later operating system	Prepare documents used in this filing.
Microsoft Excel	2007	Windows XP - SP2 or later operating system	Used to prepare the majority of the filing.
Vertex E-CIS	V5R1	IBM iSeries server running at a minimum of oS/400 V5R3	Customer information and billing system which is utilized to provide the billing determinants for developing the proposed rates.
Harris Financials	Accounts Payable - V5R3 General Ledger - V5R2 Accounts Receivable - V5R2 Inventory - V5R3 Payroll - V5R2	IBM iSeries server running at a minimum of oS/400 V5R3	Used to accumulate payroll, general ledger, accounts payable and inventory data for use in workpapers which support the financial schedules in this filing.
Allegro	version 8	Windows Server 2003 SQL or Oracle database	Used to for accumulating data on gas costs and transportation billing utilized to provide the billing determinants for developing the proposed rates.
PowerPlant	v 9.0	UNIX or Windows 2000/2003 Oracle Database 9.2 to 10g (Enterprise, Standard, or Standard One)	Used to accumulate fixed asset and depreciation data for use in workpapers which support the financial schedules in this filing.
PowerTax	v 9.0	UNIX or Windows 2000/2003 Oracle Database 9.2 to 10g (Enterprise, Standard, or Standard One)	Used to accumulate data pertaining to income tax provision and deferred income taxes for use in workpapers which support the financial schedules in this filing.
Cognos	Cognos 8 ReportNet 1.1 MR2	Windows operating system on a server with either a Oracle, DB2 or SQL database	Query tool used to develop reports from the data in the Vertex and Harris systems. These reports are used to accumulate data included in the workpapers which support this filing.
Microsoft Visual Basic for Applications	Office Professional 2007	PC running Windows 7 or Vista	Schedules prepared by the Prime Group to support their testimony.
Depreciation Model	2010	PC runningDebian or Ubuntu Linux with open-source GNU C++ compiler (GCC) and GNU scientific library (GSL)	Schedules prepared by the Prime Group to support their testimony.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(p)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Prospectuses of the most recent stock or bond offerings.

Response:

See attached.

PROSPECTUS

Rating:
Standard & Poor's: AAA
(see "Rating" herein)

$40,000,000

DELTA NATURAL GAS COMPANY, INC.

5.75% Insured Quarterly Notes (IQ Notes[SM*]) due April 1, 2021

We are offering $40,000,000 of our 5.75% Insured Quarterly Notes due April 1, 2021. We will receive all the net proceeds from this sale.

We will pay interest on the notes quarterly, beginning July 1, 2006. The notes will mature on April 1, 2021.

We have the right to redeem your notes at any time on or after April 1, 2009 at 100% of their principal value, plus any accrued but unpaid interest on your notes. We will also redeem the notes, subject to limitations, at the option of the representative of any deceased beneficial owner of the notes.

The notes will not be listed on any national securities exchange. The notes will be unsecured and will rank equally with all of our other unsecured and unsubordinated debt from time to time outstanding.

Payments of principal and interest on the notes when due will be insured by a financial guaranty insurance policy to be issued by Ambac Assurance Corporation.

Ambac

Investing in our notes involves risks. See "Risk Factors" beginning on Page 5.

	Per $1,000 Note	Total
Public offering price	$1,000	$40,000,000
Underwriting discount	$ 24	$ 960,000
Proceeds, before expenses, to us	$ 976	$39,040,000

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriter expects to deliver the notes in book-entry form through the facilities of The Depository Trust Company on or about April 6, 2006.

*IQ Notes is a service mark of Edward D. Jones & Co., L.P.

Edward Jones

The date of this prospectus is April 3, 2006.

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PROSPECTUS SUMMARY

This summary highlights selected information in this prospectus. This summary is not complete and does not contain all of the information that you should consider before investing in our notes. You should read this entire prospectus carefully before investing in our notes.

The Company

We sell natural gas to approximately 40,000 retail customers on our distribution system in central and southeastern Kentucky. Additionally, we transport natural gas to our industrial customers, who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system, and we produce a relatively small amount of natural gas from our southeastern Kentucky wells.

Our Address and Telephone Number

Our executive offices are located at 3617 Lexington Road, Winchester, Kentucky 40391. Our telephone number is (859) 744-6171. Our facsimile number is (859) 744-6552, and our internet address is www.deltagas.com.

The Offering

Notes offered by us	$40,000,000 in aggregate principal amount
Maturity	April 1, 2021
Interest	5.75% per annum payable quarterly on each January 1, April 1, July 1 and October 1, beginning on July 1, 2006
Redemption option of a deceased beneficial owner's representative	We will redeem the notes at the option of the representative of any deceased beneficial owner of a note at 100% of the principal amount, plus any interest accrued up to (but not including) the redemption date, subject to the conditions that, during the period from the original issue date of a note through April 1, 2007 and during each twelve month period after April 1, 2007, the maximum principal amount we are required to redeem is $25,000 per deceased beneficial owner and an aggregate of $800,000 for all deceased beneficial owners. See "Description of the Notes - Limited Right of Redemption upon Death of Beneficial Owner".
Our right to redeem the notes	Beginning on April 1, 2009, we are permitted to redeem your notes. We may redeem your notes at 100% of their principal value. We also must pay you any accrued but unpaid interest on your notes. See "Description of the Notes - Optional Redemption".

Use of proceeds	To redeem our outstanding 7.15% Debentures due in 2018 and our outstanding 6⅝% Debentures due in 2023 and to reduce our short-term indebtedness.
Insurance	The timely payment of scheduled principal of and interest on the notes will be insured by a financial guaranty insurance policy to be issued by Ambac Assurance Corporation.
Rating	We anticipate that the notes will be rated "AAA" by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold the notes. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that circumstances warrant that change.

Consolidated Ratio of Earnings to Fixed Charges

The following table sets forth our consolidated ratios of earnings to fixed charges for the periods indicated:

For the six and twelve months ended December 31, 2005		For the years ended June 30,				
six months	twelve months	2005	2004	2003	2002	2001
2.54x	2.97x	2.80x	2.40x	2.34x	2.22x	2.14x

The ratio of earnings to fixed charges represents the number of times that fixed charges are covered by earnings. Earnings for the calculation consist of net income before income taxes and fixed charges. Fixed charges consist of interest expense, amortization of debt expense and an estimate of the interest within rental expense.

RISK FACTORS

Purchasing our notes involves risks. The following are material risks.

You should carefully consider each of the following factors and all of the information in this prospectus before purchasing any of our notes.

Weather conditions may cause our revenues to vary from year to year. Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 75% of our annual gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, which would reduce our revenues and profits. Our weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, only partially mitigates this risk. We adjust our rates to residential and small non-residential customers to reflect variations from thirty-year average weather for our November through March billing cycles.

Changes in federal regulations could reduce the availability or increase the cost of our interstate gas supply. We purchase almost all of our gas supply from interstate sources. For example, in our fiscal year ended June 30, 2005, approximately 99% of our gas supply was purchased from interstate sources. The Federal Energy Regulatory Commission regulates the transmission of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies in a manner that could increase transportation rates or reduce pipeline or storage capacity available to us.

Our gas supply depends upon the availability of adequate pipeline transportation capacity. We purchase almost all of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of gas.

Our customers are able to acquire natural gas without using our distribution system. Our larger customers can obtain their natural gas supply by purchasing their natural gas directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution system creates a risk of the loss of large customers and thus could result in lower revenues and profits.

We face regulatory uncertainty at the state level. We are regulated by the Kentucky Public Service Commission. The majority of our revenues are generated by our regulated segment. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability.

Volatility in the price of natural gas could reduce our profits. Significant increases in the price of natural gas will likely cause our retail customers to conserve or switch to alternate sources of energy. Any decrease in the volume of gas we sell that is caused by such actions will reduce our revenues and profits. Higher prices could also make it more difficult to add new customers. Natural gas prices have risen significantly in the past year.

We do not generate sufficient cash flows to meet all our cash needs. Historically, we have made large capital expenditures in order to finance the maintenance, expansion and upgrading of our distribution system. As a result, we have funded a portion of our cash needs through borrowing and by offering new securities into the market. For example, by a combination of increasing our borrowing under our short-term line of credit and sales of securities through our dividend reinvestment plan and other offerings, we generated cash in the amount of $1,987,000 in fiscal 2005 and $4,515,000 in fiscal 2004. Although cash needs vary from year to year, we consider these years indicative of our future needs for external cash. Our dependency on external sources of financing creates the risks that our profits could decrease as a result of high capital costs and that lenders could impose onerous and unfavorable terms on us as a condition to granting us loans. We also risk the possibility that we may not be able to secure external sources of cash necessary to fund our operations.

Substantial operational risks are involved in operating a natural gas distribution, pipeline and storage system and such operational risks could reduce our revenues and increase expenses. There are substantial risks associated with the operation of a natural gas distribution, pipeline and storage system, such as operational hazards and unforeseen interruptions caused by events beyond our control. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage and environmental pollution, which in turn could lead to substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. Liabilities incurred that are not fully covered by insurance could adversely affect our results of operations and financial condition. Additionally, interruptions to the operation of our gas distribution, pipeline or storage system caused by such an event could reduce our revenues and increase our expenses.

Hurricanes or other extreme weather could interrupt our gas supply and increase natural gas prices. Hurricanes or other extreme weather could damage production or transportation facilities, which could result in decreased supplies of natural gas and increased supply costs for us and higher prices for our customers.

There is no public market for our notes. There is no public trading market for the notes. We do not intend to apply for listing of the notes on any national securities exchange or for quotation of the notes on any automated dealer quotation system. Our underwriter has told us it intends to make a market in the notes after this offering, although the underwriter is under no obligation to do so and may discontinue any market-making activities at any time without any notice. As a result, we can give no assurances that an active public market for the notes will develop. If an active public trading market for the notes does not develop, the market price and liquidity of the notes may be adversely affected.

Rating of our notes may change. If the notes are rated by a rating agency, the rating will primarily reflect the financial strength of Ambac Assurance Corporation as the issuer of the financial guaranty insurance policy insuring the payment of scheduled interest on and principal of the notes and the rating could change in accordance with Ambac Assurance Corporation's financial strength. Any rating is not a recommendation to purchase, sell or hold the notes and will not comment as to the market price of the notes or suitability of the notes for a particular investor. In addition, there can be no assurance that a rating will be maintained for any given period of time or that a rating will not be lowered or withdrawn in its entirety. Any such downward revision or withdrawal of such rating may have an adverse effect on the market price of the notes. The rating of the notes may not reflect the potential impact of all risks related to the structure and other factors on any trading market for, or trading value of, your notes.

Cross-default provisions in our borrowing arrangements increase the consequences of a default on our part. Each indenture under which our outstanding debentures were issued, the indenture under which the notes will be issued and the loan agreement for our bank line of credit, contains a cross-default provision which provides that we will be in default under such indenture or loan agreement in the event of certain defaults under any of the other indentures or loan agreement. Accordingly, should an event of default occur under one of our debt agreements, we face the prospect of being in default under all of our debt agreements and obliged in such instance to satisfy all of our then-outstanding indebtedness. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us.

Our borrowing arrangements include various negative covenants that restrict our activities. Our bank line of credit restricts us from:

- merging with another entity,
- selling a material portion of our assets other than in the ordinary course of business,

- issuing stock which in the aggregate exceeds five percent (5%) of our outstanding shares of common stock, and
- having any person hold more than twenty percent (20%) of our outstanding shares of common stock,

without bank approval or repaying the line of credit. The indenture under which notes will be issued prevents us from assuming additional mortgage indebtedness in excess of $5,000,000 or from paying dividends on our common stock unless our consolidated shareholders' equity minus the value of our intangible assets exceeds $25,800,000. The indenture governing the debentures that will remain outstanding following the application of proceeds from this offering has these same restrictions. These negative covenants create the risk that we may be unable to take advantage of business and financing opportunities as they arise.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our earnings and financial condition. Terrorist attacks, such as the attacks that occurred in New York, Pennsylvania and Washington, D.C. on September 11, 2001, and future war or risk of war may adversely impact our results of operations, our ability to raise capital and our future growth. The impact that possible terrorist attacks may have on our industry in general, and on us in particular, is not known at this time but could likely lead to increased volatility in gas rates. Uncertainty surrounding the current military action in Iraq, future military strikes or sustained military campaigns may impact our operations in unpredictable ways, including disruptions of fuel or gas supplies and markets, and the possibility that infrastructure facilities, including pipelines, processing plants and storage facilities, could be direct targets or indirect casualties of an act of terror. Terrorist activity may also hinder our ability to transport gas if transportation facilities or pipelines become damaged as a result of an attack. In addition, war or risk of war may have an adverse effect on the economy in our service territory. A lower level of economic activity could result in a decline in energy consumption which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of terrorism or war also could affect our ability to raise capital.

WHERE TO FIND MORE INFORMATION ABOUT US

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission under the Securities Exchange Act of 1934. You may read and copy this information at the Public Reference Room of the SEC, 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

The SEC also maintains an internet website that contains reports, proxy statements and other information about issuers, like us, who file electronically with the SEC. The address of that website is www.sec.gov. You may also view these documents on the "Financials" page of our internet website at www.deltagas.com.

We have filed with the SEC a registration statement on Form S-3 that registers the notes we are offering. The registration statement, including the attached exhibits and schedules, contains additional relevant information about us and the notes being offered. The rules and regulations of the SEC allow us to omit certain information included in the registration statement from this prospectus.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The SEC allows us to "incorporate by reference" into this prospectus information that we file separately with the SEC. This enables us to disclose important information to you by referring you to another document that we filed with the SEC. Information that we incorporate by reference in this manner is considered to be a part of this prospectus, except for any information that is superseded by information that is included directly in this document.

We incorporate by reference the following documents, which we previously filed with the SEC (Commission File No. 000—8788) and which contain important information about us and our financial condition:

- Our Annual Report on Form 10-K (as amended on Form 10-K/A) for the year ended June 30, 2005.
- The portions of our Definitive Proxy Statement on Schedule 14A for our Annual Meeting of Shareholders held on November 17, 2005, that are incorporated by reference into Items 10, 11, 12, 13 and 14 of our Annual Report on Form 10-K (as amended on Form 10-K/A) for the year ended June 30, 2005.
- Our Quarterly Report on Form 10-Q for the quarter ended September 30, 2005.
- Our Quarterly Report on Form 10-Q for the quarter ended December 31, 2005.
- Our Current Report on Form 8-K filed with the SEC on November 18, 2005.

We also incorporate by reference all documents that we file with the SEC pursuant to Sections 13(a), 13(c), 14, or 15(d) of the Securities Exchange Act of 1934 after the date of filing the registration statement of which this prospectus forms a part and prior to the termination of this offering.

Upon your written or oral request, we will provide you a copy of any of the filings that are incorporated by reference into this prospectus. This information will be provided to you without charge. Your request should be directed to: Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391, telephone number (859) 744-6171, facsimile number (859) 744-6552, e-mail ebennett@deltagas.com.

FORWARD-LOOKING STATEMENTS

This prospectus and documents incorporated herein by reference contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as "estimates," "attempts," "expects," "monitors," "plans," "anticipates," "intends," "continues," "believes" and similar expressions.

These forward-looking statements include, but are not limited to, statements about:

- our operational plans,
- the cost and availability of our natural gas supplies,
- our capital expenditures,
- sources and availability of funding for our operations and expansion,
- our anticipated growth and growth opportunities through system expansion and acquisition,
- competitive conditions that we face,
- our production, storage, gathering and transportation activities,
- regulatory and legislative matters,
- dividends, and
- the issuance of the financial guaranty insurance policy and the rating on the notes.

Factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results include the impact or outcome of:

- the ongoing restructuring of the natural gas industry and the outcome of the regulatory proceedings related to that restructuring,
- the changing regulatory environment, generally,

- a change in the rights under present regulatory rules to recover for costs of gas supply, other expenses and investments in capital assets,
- uncertainty of our capital expenditure requirements,
- changes in economic conditions, demographic patterns and weather conditions in our retail service areas,
- changes affecting our cost of providing gas service, including changes in gas supply costs, interest rates, the availability of external sources of financing for our operations, tax laws, environmental laws and the general rate of inflation,
- changes affecting the cost of competing energy alternatives and competing gas distributors,
- changes in accounting principles and tax laws or the application of such principles and laws to us, and
- other matters described in the "RISK FACTORS" section beginning on page 5.

USE OF PROCEEDS

We anticipate the net proceeds from this offering, after deducting the underwriting discount and expenses payable by us, will be approximately $37.7 million. We will use approximately $23.7 million of these estimated net proceeds to redeem our 7.15% Debentures due 2018 and approximately $10.2 million of these estimated net proceeds to redeem our 6⅝% Debentures due 2023. We will use the balance of the net proceeds from this offering, which we estimate to be approximately $3.8 million, to reduce the outstanding balance of our revolving bank line of credit with Branch Banking and Trust Company. As of March 27, 2006, the outstanding principal balance of this bank line of credit was $15,685,123, and it accrued interest at the rate of 5.64% per annum. The amount repaid on our line of credit by the net proceeds from this offering may be redrawn.

CAPITALIZATION

The following tables set forth our consolidated capitalization and short-term debt as of December 31, 2005, and as adjusted to reflect the sale of the notes and the application of the estimated net proceeds. This table should be read in conjunction with our consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended June 30, 2005, and our Quarterly Report on Form 10-Q for the quarter ended December 31, 2005, both of which are incorporated by reference into this prospectus.

	As of December 31, 2005		
	Actual	**As Adjusted**	**Percentage of as Adjusted**
Common Stockholders' Equity	$ 51,524,275	$ 51,524,275	46.2%
Long-Term Debt (including amounts due within one year)	53,841,000	59,990,000	53.8%
Total Capitalization	$105,365,275	$111,514,275	100.0%
Short-Term Debt	$ 32,034,527	$ 28,182,527	

DESCRIPTION OF THE NOTES

We are offering $40,000,000 aggregate principal amount of our 5.75% Insured Quarterly Notes due April 1, 2021.

We currently have outstanding 7.15% Debentures due 2018 in the aggregate principal amount of $23,681,000, 6⅝% Debentures due 2023 in the aggregate principal amount of $10,170,000 and 7% Debentures due 2023 in the aggregate principal amount of $19,990,000. The 7.15% Debentures due 2018 and the 6⅝% Debentures due 2023 will be paid in full with a portion of the proceeds of this offering. While we issued these debentures under indentures different from the indenture under which this offering is made and the debentures have slightly different terms from the notes being offered by this prospectus, the outstanding debentures mainly differ from the notes offered by this prospectus as to interest rate and maturity date. These debentures and our $40,000,000 short-term line of credit with Branch Banking and Trust Company, which as of March 27, 2006, had an outstanding principal balance of $15,685,123, constitute all our unsubordinated, unsecured debt obligations. The 7% Debentures due 2023 and our short-term line of credit with Branch Banking and Trust Company will rank equally as our debt obligations to the notes offered by this prospectus. As discussed above, we will use approximately $3.8 million of the proceeds of this offering to pay a portion of the outstanding balance on the short-term bank line of credit.

We will issue the notes under an indenture dated as of March 1, 2006, between us and The Bank of New York Trust Company, N.A., as the trustee. We have filed a copy of the indenture with the SEC.

The indenture is a contract between us and the trustee. The trustee has two main roles. First, the trustee can enforce your rights against us if an "event of default," as that term is described below, occurs. Second, the trustee performs certain administrative duties for us.

The terms of the notes include those stated in the indenture and those made a part of the indenture by reference to the Trust Indenture Act of 1939, as in effect on March 1, 2006. We have summarized below the material provisions of the notes and the indenture. However, you should understand that this is only a summary, and we have not included all of the provisions of the notes or the indenture. We have filed the indenture with the SEC, and we suggest that you read the indenture. We are incorporating by reference the provisions of the indenture and this summary is qualified in its entirety by the provisions of the indenture.

We do not intend to list the notes on a national securities exchange. The notes do not presently have a trading market. We can give no assurance that such a market will develop. If a market for the notes does develop, there can be no assurance that it will continue to exist.

Book-Entry Only System

We will issue the notes in the aggregate initial principal amount of $40,000,000. The notes will be represented by one global certificate (also known as a global security) issued to The Depository Trust Company, which is known as DTC. DTC will act as securities depository for the notes. The notes will be issued only as fully-registered securities registered in the name of DTC's nominee, Cede & Co. DTC will maintain the notes in denominations of $1,000, and integral multiples of $1,000, through its book-entry facilities.

The following is based upon information furnished by DTC:

- DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds securities that its participants (known as direct participants) deposit with DTC. DTC also facilitates the post-trade settlement among direct participants of sales and other securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry transfers and pledges between direct participants' accounts. This eliminates the need for physical movement of securities certificates. Direct participants in DTC include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is a wholly-owned subsidiary of Depository Trust & Clearing Corporation, which in turn is owned by a number of direct participants and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation and Emerging Markets Clearing Corporation, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others, known as indirect participants, such as securities brokers and dealers, banks, trust companies and clearing corporations that clear transactions through or maintain a custodial relationship with a direct participant. The rules applicable to DTC and its participants are on file with the SEC. More information about DTC can be found at www.dtcc.com and www.dtc.org.

- Purchases of notes within the DTC system must be made by or through direct participants, which will receive a credit for the notes on DTC's records. The ownership interest of each actual purchaser of an interest in the notes, the owners of which are known as beneficial owners, is in turn to be recorded on the direct and indirect participants' records. Beneficial owners like yourself will not receive written confirmation from DTC of their purchase, but beneficial owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the direct or indirect participants through which the beneficial owners entered into the transaction. Transfers of the notes are to be accomplished by entries made on the books of direct and indirect participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing the notes, except in the event that use of the book-entry system for the notes is discontinued, as discussed below.
- To facilitate subsequent transfers, all notes deposited by participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of notes with DTC and their registration in the name of Cede & Co. effect no change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the notes. DTC's records reflect only the identity of the direct participants to whose accounts the notes are credited, which may or may not be the beneficial owners. The direct and indirect participants will remain responsible for keeping account of their holdings on behalf of their customers.
- The delivery of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial owners like yourself may wish to take certain steps to augment transmission of notices of significant events with respect to the notes, such as redemptions, tenders and defaults.
- Redemption notices will be sent to Cede & Co., as registered holder of the notes. If less than all of the notes are being redeemed, DTC's practice is to determine by lot the amount of the interest of each direct participant to be redeemed.
- Neither DTC nor Cede & Co. (nor any other DTC nominee) will itself consent or vote with respect to notes. Under its usual procedures, DTC mails an Omnibus Proxy to us as soon as possible after the record date for any event giving holders of notes a voting opportunity. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those direct participants to whose accounts the notes are credited on the record date (identified in a listing attached to the Omnibus Proxy).
- Principal and interest payments on the notes will be made to Cede & Co., or such other nominee as may be requested by DTC. DTC's practice is to credit direct participants' accounts upon DTC's receipt of funds and corresponding detail information from us or the trustee on the relevant payment date in accordance with their respective holdings shown on DTC's records. Payments by direct or indirect participants to beneficial owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such direct or indirect participants and not of DTC, the trustee, you or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment or principal and interest to Cede & Co. (or such other nominee as may be

requested by an authorized representative of DTC) will be the responsibility of the trustee as paying agent under the indenture, disbursement of payments to direct participants will be the responsibility of DTC, and further disbursement of payments to the beneficial owners will be the responsibility of direct and indirect participants.

- So long as DTC is the registered owner of the notes, we and the trustee will consider DTC as the sole owner or holder of the notes for all purposes under the indenture and any applicable laws. As a beneficial owner of interests in the notes, you will not be entitled to receive a physical certificate representing your ownership interest and you will not be considered an owner or holder of the notes under the indenture, except as otherwise provided below. You, as a beneficial owner, will have the right to sell, transfer or otherwise dispose of an interest in the notes and the right to receive the proceeds from the notes and all interest, principal and premium payable on the notes. Your beneficial interest in the notes will be recorded, in integral multiples of $1,000, on the records of DTC's direct participant that maintains your account. In turn, this interest held by DTC's direct participant in the notes will be recorded, in integral multiples of $1,000, on the computerized records of DTC. Beneficial ownership of the notes may be transferred only by compliance with the procedures of DTC and the DTC direct (or, as applicable, indirect) participant that maintains your account.
- All rights of ownership must be exercised through DTC and the book-entry system, except that you are entitled to exercise directly your rights under Section 316(b) of the Trust Indenture Act of 1939 with respect to the payment of interest and principal on the notes. Notices that we or the trustee give under the indenture will be given only to DTC. We expect DTC will forward the notices to its participants by its usual procedures, so that its participants may forward the notices to the beneficial owners like yourself. Neither we nor the trustee will have any responsibility or obligation to assure that any notices are forwarded by DTC to its direct participants or by its direct participants to the beneficial owners of the notes.

DTC may discontinue providing its services as securities depository for the notes at any time by giving reasonable written notice to us and the trustee. Under such circumstances, and in the event that we do not obtain a successor securities depository, we will deliver note certificates to the beneficial owners. We may decide to replace DTC or any successor depository. Additionally, we may decide to discontinue use of the system of book-entry transfers through DTC or a successor depository. In that event, we will print and deliver to the beneficial owners certificates for the notes.

According to DTC, the foregoing information with respect to DTC is provided to the financial community for informational purposes only and is not intended to serve as a representation, warranty or contract modification of any kind. The information in this section concerning DTC and DTC's book-entry system and procedures has been obtained from third-party sources that we believe are reliable. Neither we, the underwriter nor the trustee will have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership of the notes or for maintaining, supervising or reviewing any records relating to the beneficial ownership of notes.

Except as provided in this prospectus, you and other beneficial owners of the notes may not receive physical delivery of notes. Accordingly, you and each other beneficial owner must rely on the procedures of DTC to exercise any rights under the notes.

Interest and Payment

The notes will mature on April 1, 2021. The notes will bear interest from the date of issuance at the annual interest rate stated on the cover page of this prospectus. The amount of interest payable will be calculated on the basis of a 360-day year of twelve 30-day months. Interest will be payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year, beginning on July 1, 2006. Interest will be paid to the persons in whose names the notes are registered at the close of business on the 15th day of the month immediately preceding the applicable interest payment date. If any payment date would otherwise be a day that is a holiday under the indenture, which includes each Saturday, Sunday and other bank holidays, the payment will be postponed to the next day that is not a holiday. No interest will accrue on an interest payment for the period from and after a scheduled payment date that is postponed because of a holiday.

So long as DTC is the registered owner of the notes, the trustee as paying agent will make payments of interest, principal and premium on the notes to DTC. DTC will be responsible for crediting the amount of the distributions to the accounts of its participants entitled to the distributions, in accordance with DTC's normal procedures. Each of DTC's direct participants will be responsible for disbursing distributions to indirect participants, if applicable, or to you and the other beneficial owners of the interests in notes that it represents.

Neither we nor the trustee will have any responsibility or liability for any aspect of:

- the records relating to, notices to, or payments made on account of, beneficial ownership interests in the notes, including your interest;
- maintaining, supervising or reviewing any records relating to beneficial ownership interests in the notes, including your interest;
- the selection of any beneficial owner, including you, of the notes to receive payment in the event of a partial redemption of the global security; or
- consents given or other action taken on behalf of any beneficial owner, including you, of the notes.

Optional Redemption

Under the indenture, we have the option to redeem all or part of the notes before their stated maturity. We may redeem all or part of the notes at any time on or after April 1, 2009. If we redeem all or part of the notes, we must pay 100% of the principal amount of the notes being redeemed, plus accrued interest on those notes up to but not including the date of such redemption.

If we redeem fewer than all the notes, the trustee will select by lot the particular notes to be redeemed.

We will give notice of redemption at least 30 days before the date of redemption to each holder of notes to be redeemed at the holder's registered address. We may rescind any notice of redemption at any time at least five days prior to the date of redemption.

On and after the date of redemption, interest will cease to accrue on notes or portions of the notes redeemed. However, interest will continue to accrue if we default in the payment of the amount due upon redemption.

Subject to the foregoing and to applicable law, we may, at any time and from time to time, purchase outstanding notes by tender, in the open market or by private agreement.

Limited Right of Redemption Upon Death of Beneficial Owner

Unless the notes have been declared due and payable prior to their maturity by reason of an event of default under the indenture, the representative of a deceased beneficial owner of interests in the notes has the right at any time to request redemption prior to stated maturity of all or part of his interest in the notes. We will redeem these interests in the notes subject to the limitations that we will not be obligated to redeem, during the period from the original issue date through and including April 1, 2007 (known as the "initial period"), and during any twelve-month period which ends on and includes each April 1 thereafter (each such twelve-month period being known as a "subsequent period"), on behalf of a deceased beneficial owner any interest in the notes which exceeds $25,000 principal amount or interests in the notes exceeding $800,000 in aggregate principal amount.

We may, at our option, redeem interests of any deceased beneficial owner in the notes in the initial period or any subsequent period in excess of the $25,000 limitation. Any such redemption, to the extent that it exceeds the $25,000 limitation for any deceased beneficial owner, will not be included in the computation of the $800,000 aggregate limitation for that initial period or that subsequent period, as the case may be, or for any succeeding subsequent period. We may, at our option, redeem interests of deceased beneficial owners in the notes, in the initial period or any subsequent period, in an aggregate principal amount exceeding $800,000. Any redemption so made, to the extent it exceeds the $800,000 aggregate limitation, will not reduce the $800,000 aggregate limitation for any subsequent period. If we elect to redeem notes in excess of the $25,000 limitation or the $800,000 aggregate limitation, notes so redeemed will be redeemed in the order of the receipt of redemption requests by the trustee.

A request for redemption of an interest in the notes may be initiated by the representative of the deceased beneficial owner. For purposes of making a redemption request, the representative of a deceased beneficial owner is any person who is the personal representative or other person authorized to represent the estate of the deceased beneficial owner or the surviving joint tenant or tenant(s) by the entirety or the trustee of a trust. The representative must deliver a request to the participant through whom the deceased beneficial owner owned the interest to be redeemed, in form satisfactory to the participant, together with evidence of the death of the beneficial owner, evidence of the authority of the representative satisfactory to the participant, such waivers, notices or certificates as may be required under applicable state or federal law and such other evidence of the right to redemption as the participant may require. The request will specify the principal amount of the interest in the notes to be redeemed. The participant will thereupon deliver to DTC a request for redemption substantially in the form attached as Appendix A to this prospectus (known as the "redemption request"). DTC will, on receipt of a redemption request, forward the redemption request to the trustee. The trustee will maintain records with respect to redemption requests received by it including date of receipt, the name of the participant filing the redemption request and the status of each redemption request with respect to the $25,000 limitation and the $800,000 aggregate limitation. The trustee will immediately file with us each redemption request it receives, together with the information regarding the eligibility of that redemption request with respect to the $25,000 limitation and the $800,000 aggregate limitation. We, DTC and the trustee may conclusively assume, without independent investigation, that the statements contained in each redemption request are true and correct and will have no responsibility for reviewing any documents submitted to the participant by the representative. We, DTC and the trustee will also have no responsibility for determining whether the applicable decedent is in fact the beneficial owner of the interest in the notes to be redeemed or is in fact deceased and whether the representative is duly authorized to request redemption on behalf of the applicable beneficial owner.

Subject to the $25,000 limitation and the $800,000 aggregate limitation, we will, after the death of any beneficial owner, redeem the interest of that beneficial owner in the notes on the next interest payment date occurring not less than 30 days following our receipt of a redemption request from the trustee. If redemption requests exceed the $800,000 aggregate limitation during the initial period or during any subsequent period, then the excess redemption requests will be applied in the order received by the trustee to successive subsequent periods, regardless of the number of subsequent periods required to redeem such interests. We may, at any time, notify the trustee that we will redeem, on the next interest payment date occurring not less than 30 days after that notice, all or any lesser amount of notes for which redemption requests have been received but which are not then eligible for redemption by reason of the $25,000 limitation or the $800,000 aggregate limitation. If we so elect to redeem excess notes, we will redeem these excess notes in the order of receipt of redemption requests by the trustee.

The price we will pay for the interests in the notes to be redeemed pursuant to a redemption request is 100% of the principal amount of the interests plus accrued but unpaid interest to the date of payment. Subject to arrangements with DTC, payment for interests in the notes which are to be redeemed will be made to DTC upon presentation of notes to the trustee for redemption in the aggregate principal amount specified in the redemption requests submitted to the trustee by DTC which are to be fulfilled in connection with that payment. The principal amount of any notes we acquire or redeem, other than by redemption at the option of any representative of a deceased beneficial owner, will not be included in the computation of either the $25,000 limitation or the $800,000 aggregate limitation for the initial period or for any subsequent period.

A beneficial owner, for purposes of determining if the representative of a deceased person may make a proper redemption request, is the person who has the right to sell, transfer or otherwise dispose of an interest in a note and the right to receive the proceeds from that interest, as well as the interest and principal payable to the holder of the note. In general, a determination of beneficial ownership in the notes will be subject to the rules, regulations and procedures governing DTC and its participants.

Any interest in a note held in tenancy by the entirety, joint tenancy or by tenants in common will be considered to be held by a single beneficial owner and the death of a tenant by the entirety, joint tenant or tenant in common will be considered the death of a beneficial owner. The death of a person who, during his lifetime, was entitled to substantially all of the rights of a beneficial owner of an interest in the notes will be considered the death of the beneficial owner, regardless of the recordation of such interest on the records of the participant, if such rights can be established to the satisfaction of the participant. These rights will be considered to exist in typical cases of nominee ownership, ownership under the Uniform Gifts to Minors Act or the Uniform Transfer to Minors Act, community property or other similar joint ownership arrangements, including individual retirement accounts or Keogh [H.R. 10] plans maintained solely by or for the decedent or by or for the decedent and any spouse, trusts and certain other arrangements where one person has substantially all of the rights of a beneficial owner during such person's lifetime.

In the case of a redemption request which is presented on behalf of a deceased beneficial owner and which has not been fulfilled at the time we give notice of our election to redeem the notes, the notes which are the subject of such pending redemption request will be redeemed prior to any other notes.

Any redemption request may be withdrawn by the person(s) presenting the redemption request upon delivery of a written request for withdrawal given by the participant on behalf of that person to DTC and by DTC to the trustee not less than 60 days prior to the interest payment date on which the notes are eligible for redemption. We may, at any time, purchase any notes for which redemption requests have been received in lieu of redeeming those notes. Any notes we purchase in this manner will either be re-offered for sale and sold within 180 days after the date of purchase or presented to the trustee for redemption and cancellation.

During any time or times as the notes are not represented by a global certificate and are issued in definitive form, all references herein to participants and DTC, including DTC's governing rules, regulations and procedures, will be considered deleted, all determinations which under this section the participants are required to make will be made by us (including, without limitation, determining whether the applicable decedent is in fact the beneficial owner of the interest in the notes to be redeemed or is in fact deceased and whether the representative is duly authorized to request redemption on behalf of the applicable beneficial owner), all redemption requests, to be effective, must be delivered by the representative to the trustee, with a copy to us, and must be in the form of a redemption request (with appropriate changes to reflect the fact that the redemption request is being executed by a representative) and, in addition to all documents that are otherwise required to accompany a redemption request, must be accompanied by the note that is the subject of the request.

No Sinking Fund

The notes are not subject to a sinking fund requirement, which means we will not deposit money on a regular basis into any separate custodial account to repay the notes.

Notes Not Convertible

The notes are not convertible into any other security.

Notes Unsecured

The notes are unsecured obligations and are equal in rank to all of our other unsecured and unsubordinated debt that may be outstanding at any time. Subject only to the restrictions described below, the indenture does not limit the amount of debt which we may incur.

Restrictive Covenants

Under the indenture, we agreed to the following restrictions:

- We, and our subsidiaries, may not create, issue, incur, guarantee or assume any long-term debt, which ranks prior to or equal to the notes in right of payment, unless, after the creation, issuance, incurrence or assumption of the additional long-term debt, the net book value of all of our and our subsidiaries' physical property is at least equal to all of our and our subsidiaries' then outstanding long-term debt. We are required to include the notes outstanding in calculating our long-term debt. For purposes of this debt limitation, long-term debt is generally calculated as any of our or our subsidiaries' indebtedness that is not payable on demand or not required to be paid within one year after the calculation is made. For purposes of this limitation, our and our subsidiaries' physical property is limited to physical property used or useful to us in the business of furnishing or distributing gas service as a public utility. As of December 31, 2005, after giving effect to the issuance of the notes and the application of the proceeds from the sale of the notes, the net book value of all of our and our subsidiaries' physical property would have exceeded our and our subsidiaries' long-term debt by $58,701,098.

- We may not declare or pay any dividends or make any other distribution upon our common stock, and we may not apply any of our assets to the redemption, retirement, purchase or other acquisition of any of our capital stock. This restriction does not apply:
  - if after the declaration, payment, distribution or application of assets our shareholders' equity, less the book value of our and our subsidiaries' intangible assets, is at least equal to $25,800,000 as reflected on our then latest available balance sheet (our December 31, 2005 balance sheet, after giving effect to the issuance of the notes, reflects that our shareholders' equity is $51,524,275); or
  - to dividends and distributions consisting only of shares of our common stock, but not cash or other property; or
  - to purchases or redemptions of our preferred stock in compliance with any mandatory sinking fund, purchase fund or redemption requirement.
- We may not issue, assume or guarantee any debt secured by a lien on any property or asset that we own. However, this restriction does not apply if, prior to or at the same time as the issuance, assumption or guarantee of that debt, we equally and ratably secure the notes. This restriction is also subject to certain exceptions described in the indenture, which include liens securing debt having an aggregate outstanding principal balance of $5,000,000 or less.
- Ambac Assurance Corporation, as the insurer under the financial guaranty insurance policy for the notes that is described below, can require us to be engaged in the transmission or distribution of natural gas and be regulated as to rates, to the extent required by law, in each jurisdiction that comprises our service area.

Except as described above, the indenture does not afford any protection to holders of notes solely on account of our involvement in highly-leveraged transactions.

Successor Corporation

We agree in the indenture that we will not consolidate with, merge into or transfer or lease all or substantially all of our assets to another corporation, unless:

- no default will exist under the indenture immediately after the transaction;
- the other corporation assumes all of our obligations under the notes and the indenture; and
- certain other requirements are met.

Events of Default, Notice and Waiver

The following constitute events of default under the indenture:

- default in the payment of principal of the notes when due;
- default in the payment of any interest on the notes, when due, if continued for 30 days;
- default in the performance of any other agreement we have made in the notes or the indenture, including the restrictive covenants discussed above, if continued for 60 days after written notice;

- acceleration of certain of our or our subsidiaries' indebtedness for borrowed money under the terms of any instrument under which indebtedness of $100,000 or more is issued or secured; and
- certain events in bankruptcy, insolvency or reorganization involving us.

The trustee is required, within 90 days after the occurrence of a default, to give the holders of notes notice of all continuing defaults known to the trustee. However, in the case of a default in the payment of the principal or interest in respect of any of the notes, the trustee is protected in not giving notice if it in good faith determines that not giving notice is in the interest of the holders of the notes.

If any event of default occurs and is continuing, the trustee or the holders of at least twenty-five percent in principal amount of outstanding notes may declare the notes immediately due and payable. This acceleration may be rescinded by the holders of a majority in principal amount of the notes then outstanding, upon the conditions provided in the indenture.

The holders of a majority in principal amount of the notes may rescind an acceleration by waiving an existing default and its consequences, upon the conditions provided in the indenture. This right to waive the default and its consequences does not apply to:

- an uncured default in payment of principal or interest on the notes; or
- an uncured failure to make any redemption payment; or
- an uncured default of a provision which cannot be modified under the terms of the indenture without the consent of each holder of the notes affected.

Ambac Assurance Corporation, as the insurer under the financial guaranty insurance policy described below, will control the remedies following an event of default.

Each year we must file with the trustee a statement regarding our compliance with the terms of the indenture. This statement must be filed within 120 days after the end of each fiscal year. Further, this statement must specify any defaults of which our officers signing the statement may have knowledge.

Modification of the Indenture

We, together with the trustee, may modify and amend the indenture in a manner that materially affects the rights of the holders of the notes only if we obtain the consent of the holders of not less than a majority in principal amount of the notes then outstanding.

We, together with the trustee, may only modify or amend the indenture in a manner that materially affects the rights of the holders of the notes and that:

- changes the stated maturity of any note, or
- reduces the principal amount of or interest rate on any note, or
- changes the interest payment date or otherwise modifies the terms of payment of the principal of or interest on the notes, or
- reduces the percentage required for any consent, waiver or modification, or
- modifies certain other provisions of the indenture,

with the consent of each holder of any note affected by the modification or amendment.

The consent of Ambac Assurance Corporation, as the insurer under the financial guaranty insurance policy, is required with respect to any modification of the indenture that requires consent of the holders of the notes.

Discharge of the Indenture

The indenture will be discharged and canceled upon payment of all the notes by us. Payment of amounts due in respect of the notes by the Insurer pursuant to the Policy will not discharge our obligation to pay amounts due on the notes. The indenture may also be discharged upon written notice to the trustee and our deposit with the trustee of funds or U.S. Government obligations sufficient to pay the principal of and premium, if any, and interest on the notes. We may only deposit funds or U.S. Government obligations to discharge the indenture if the notes mature or are called for redemption within one year of our written notice.

Trustee

The indenture entitles the trustee to be indemnified by the holders of notes before proceeding to exercise any right or power under the indenture at the request of the holders of notes. This indemnification of the trustee is subject to the trustee's duty during default to act with the standard of care required in the indenture. The indenture provides that the holders of a majority in principal amount of the outstanding notes may direct the time, method and place of conducting any proceeding and any remedy available to the trustee or exercising any trust or power conferred upon the trustee.

The Bank of New York Trust Company, N.A., the trustee and note registrar under the indenture, has its corporate trust office in Cincinnati, Ohio. In addition to serving as trustee and note registrar under the indenture, The Bank of New York Trust Company, N.A. serves as:

- trustee and debenture registrar for our 7.15% Debentures due 2018, and
- trustee and debenture registrar for our 7% Debentures due 2023.

THE POLICY AND THE INSURER

The following information has been furnished by Ambac Assurance Corporation (the "Insurer") for use in this prospectus. Reference is made to Appendix B for a specimen of the financial guaranty insurance policy to be issued by the Insurer. No representation is made by us or our underwriter as to the accuracy or completeness of any such information.

The Policy

The Insurer has made a commitment to issue a financial guaranty insurance policy relating to the notes (the "Policy"), the form of which is attached to this prospectus as Appendix B. The following summary of the terms of the Policy does not purport to be complete and is qualified in its entirety by reference to the Policy.

Under the terms of the Policy, the Insurer will pay to The Bank of New York, New York, New York, or any successor thereto (the "Insurance Trustee"), that portion of the principal of and interest on the notes which shall become Due for Payment but shall be unpaid by reason of Nonpayment (as such terms are defined in the Policy) by us. The Insurer will make such payments to the Insurance Trustee on the later of the date on which such principal and interest becomes Due for Payment or within one business day following the date on which the Insurer shall have received notice of Nonpayment from the trustee. The insurance under the Policy will extend for the term of the notes and, once issued, cannot be canceled by the Insurer.

The Policy will insure payment only on the stated maturity date and in connection with the mandatory redemption of notes at the option of a representative of any deceased beneficial owner of the notes, in the case of principal, and on interest payment dates, in the case of interest. If the notes become subject to mandatory redemption (other than in connection with the mandatory redemption of notes at the option of a representative of any deceased beneficial owner of the notes) and insufficient funds are available for redemption of all outstanding notes, the Insurer will remain obligated to pay principal of and interest on outstanding notes on the originally scheduled interest and principal payment dates. In the event of any acceleration of the principal of the notes, the insured payments will be made at such times and in such amounts as would have been made had there not been an acceleration.

In the event the trustee has notice that any payment of principal of or interest on a note which has become Due for Payment and which is made to a holder by us or on our behalf has been deemed a preferential transfer and theretofore recovered from its registered owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such registered owner will be entitled to payment from the Insurer to the extent of such recovery if sufficient funds are not otherwise available.

The Policy does **not** insure any risk other than Nonpayment, as defined in the Policy. Specifically, the Policy does **not** cover:

- payment on acceleration, as a result of a call for redemption (other than in connection with the mandatory redemption of notes at the option of a representative of any deceased beneficial owner of the notes) or as a result of any other advancement of maturity;
- payment of any redemption, prepayment or acceleration premium; or
- nonpayment of principal or interest caused by the insolvency or negligence of the trustee.

If it becomes necessary to call upon the Policy, payment of principal requires surrender of notes to the Insurance Trustee together with an appropriate instrument of assignment so as to permit ownership of such notes to be registered in the name of the Insurer to the extent of the Payment under the Policy. Payment of interest pursuant to the Policy requires proof of holder entitlement to interest payments and an appropriate assignment of the holder's right to payment to the Insurer.

Upon payment of the insurance benefits and to the extent the Insurer makes payments of principal of or interest on the notes, the Insurer will become the owner of such note or the right to payment of principal or interest on such note and will be fully subrogated to the surrendering holder's right to payment.

The Insurer

The Insurer is a Wisconsin-domiciled stock insurance corporation regulated by the Office of the Commissioner of Insurance of the State of Wisconsin and licensed to do business in 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the Territory of Guam and the U.S. Virgin Islands, with admitted assets of approximately $8,994,000,000 (unaudited) and statutory capital of approximately $5,649,000,000 (unaudited) as of December 31, 2005. Statutory capital consists of the Insurer's policyholders' surplus and statutory contingency reserve. Moody's Investors Service, Inc. ("Moody's"), Standard & Poor's ("S&P") and Fitch Ratings have each assigned a triple-A financial strength rating to the Insurer.

The Insurer makes no representation regarding the notes or the advisability of investing in the notes and makes no representation regarding, nor has it participated in the preparation of, this prospectus other than the information supplied by the Insurer and presented under the heading "THE POLICY AND THE INSURER".

Available Information

The parent company of the Insurer, Ambac Financial Group, Inc. ("AFG"), is subject to the informational requirements of the Securities Exchange Act of 1934, and in accordance therewith files reports, proxy statements and other information with the SEC. These reports, proxy statements and other information can be read and copied at the SEC's public reference room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. The SEC maintains an internet site at www.sec.gov that contains reports, proxy and information statements and other information regarding companies that file electronically with the SEC, including AFG. These reports, proxy statements and other information can also be read at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

The following, as they relate to the Insurer, are incorporated by reference into this prospectus and are deemed to constitute part of this prospectus:

- the consolidated financial statements of Ambac Assurance Corporation and subsidiaries as of December 31, 2005 and 2004 and for each of the years in the three-year period ended December 31, 2005, prepared in accordance with U.S. generally accepted accounting principles, included in the

Annual Report on Form 10-K of Ambac Financial Group, Inc. (which was filed with the SEC on March 13, 2006, Commission File No. 1-10777).

Any statement contained in a document incorporated by reference shall be modified or superseded for the purposes of this prospectus to the extent that a statement contained or incorporated by reference in this prospectus also modifies or supersedes that statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this prospectus.

All consolidated financial statements of Ambac Assurance Corporation and subsidiaries included in documents filed by Ambac Financial Group, Inc. with the SEC pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, subsequent to the date of filing the registration statement of which this prospectus forms a part and prior to the termination of the offering of the notes are deemed to be incorporated by reference into this prospectus and to be a part of this prospectus from the respective dates of filing of the consolidated financial statements.

Copies of Ambac Assurance Corporation's financial statements prepared in accordance with statutory accounting standards are available from Ambac Assurance Corporation. The address of Ambac Assurance Corporation's administrative offices and its telephone number are One State Street Plaza, 19th Floor, New York, New York 10004 and (212) 668-0340.

RATING

It is anticipated that S&P will assign the notes a rating of "AAA", conditioned upon the issuance and delivery by the Insurer at the time of delivery of the notes of the Policy, insuring the timely payment of the principal of and interest on the notes. Such rating reflects only the views of S&P, and an explanation of the significance of such rating may be obtained only from S&P at the following address: Standard & Poor's, 25 Broadway, New York, New York 10004. There is no assurance that such rating will remain in effect for any period of time or that it will not be revised downward or withdrawn entirely by S&P if, in its judgment, circumstances warrant. Neither we nor the underwriter has undertaken any responsibility to oppose any proposed downward revision or withdrawal of a rating on the notes. Any such downward revision or withdrawal of such rating may have an adverse effect on the market price of the notes.

At present, S&P maintains four categories of investment grade ratings. They are AAA, AA, A and BBB. Standard & Poor's defines "AAA" as the highest rating assigned to a debt obligation.

UNDERWRITING

Edward D. Jones & Co., L.P. is the underwriter for this offering. Subject to the terms and conditions of the underwriting agreement, the underwriter has agreed to purchase, and we have agreed to sell to the underwriter, all of the notes. We have filed a copy of the underwriting agreement with the SEC.

The underwriting agreement provides that the obligations of the underwriter to purchase the notes are subject to the approval of a number of legal matters by its counsel as well as our counsel, and to other conditions. The underwriter is obligated to purchase all of the notes if it purchases any of the notes.

The underwriter proposes to offer the notes directly to the public initially at the public offering prices set forth on the cover page of this prospectus.

The following table shows the underwriting discount we will pay to the underwriter. These amounts show the discount paid per $1,000 purchase of the notes and the total for the purchase of all notes being offered.

	Per $1,000 Note	Total
Public offering price	$1,000	$40,000,000
Underwriting discount	$ 24	$ 960,000
Proceeds, before our expenses	$ 976	$39,040,000

We estimate that our out-of-pocket expenses for this offering, that are in addition to discounts we pay to the underwriters, will be approximately $1,337,000. These estimated expenses include our estimated premium payment for the Policy.

The underwriter intends to make a market in the notes. However, the underwriter will have no obligation to make a market in the notes and may cease market making activities at any time. The notes will not be listed on any exchange.

Until the distribution of the notes is completed, the SEC's rules may limit the ability of the underwriter to bid for and purchase the notes. As an exception to these rules, the underwriter is permitted to engage in certain transactions that stabilize the price of the notes. These transactions consist of placing bids for or effecting purchases of the notes for the purpose of pegging, fixing or maintaining the price of the notes.

If the underwriter creates a short position in the notes in connection with the offering by selling more notes than are set forth on the cover page of this prospectus, the underwriter may reduce that short position by purchasing notes in the open market. In general, purchases of a security for the purpose of stabilization or to reduce a short position could cause the price of the security to be higher than it might be in the absence of such purchases.

We and the underwriter make no representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the notes. In addition, we and the underwriter make no representations that the underwriter will engage in these types of transactions or that these transactions, once begun, will not be discontinued without notice.

The offering of the notes is made for delivery when, as and if accepted by the underwriter and subject to prior sale and to withdrawal, cancellation or modification of the offer without notice. The underwriter reserves the right to reject any order for the purchase of notes in whole or in part.

We have agreed to indemnify the underwriter and persons who control the underwriter against certain liabilities that may be incurred in connection with the offering, including liabilities under the Securities Act of 1933.

LEGAL MATTERS

Our counsel, Stoll Keenon Ogden PLLC, Lexington, Kentucky, will pass on the validity of the notes and will opine that the notes, when sold, will be our binding obligations. Certain other matters will be passed upon for the underwriter by its counsel, Armstrong Teasdale LLP, St. Louis, Missouri.

Attorneys in the firm of Stoll Keenon Ogden PLLC that have participated in this notes offering on behalf of the firm, and members of such attorneys' immediate families, own collectively 8,475 shares of our common stock.

EXPERTS

The consolidated financial statements, the related financial statement schedule and management's report on the effectiveness of internal control over financial reporting incorporated in this prospectus by reference from our Annual Report on Form 10-K (as amended on Form 10-K/A) for the year ended June 30, 2005, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports (which reports (1) express an unqualified opinion on our consolidated financial statements and financial statement schedule and include an explanatory paragraph referring to our change effective July 1, 2002 in our accounting for asset retirement obligations, (2) express an unqualified opinion on our management's assessment regarding the effectiveness of internal control over financial reporting and, (3) express an unqualified opinion on the effectiveness of internal control over financial reporting), which are incorporated herein by reference, and have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

The consolidated financial statements of Ambac Assurance Corporation and subsidiaries as of December 31, 2005 and 2004, and for each of the years in the three-year period ended December 31, 2005, are incorporated by reference in this prospectus and in the registration statement in reliance upon the report of KPMG LLP, independent registered public accounting firm, incorporated by reference in this prospectus and in the registration statement upon the authority of that firm as experts in accounting and auditing. The report of KPMG LLP refers to changes, in 2003, in Ambac Assurance Corporation's methods of accounting for variable interest entities and stock-based compensation.

APPENDIX A

FORM OF REDEMPTION REQUEST

DELTA NATURAL GAS COMPANY, INC.
5.75% INSURED QUARTERLY NOTE DUE APRIL 1, 2021
(THE "NOTE")

CUSIP NO. 247748 AG 1

The undersigned, ________________ (the "Participant"), does hereby certify, pursuant to the provisions of that certain Indenture dated as of March 1, 2006 (the "Indenture") made by Delta Natural Gas Company, Inc. (the "Company") and The Bank of New York Trust Company, N.A., as Trustee (the "Trustee"), to The Depository Trust Company (the "Depository"), the Company, and the Trustee that:

1. [Name of deceased Beneficial Owner] is deceased.

2. [Name of deceased Beneficial Owner] had a $__________ interest in the above referenced Notes.

3. [Name of Representative] is [Beneficial Owner's personal representative/other person authorized to represent the estate of the Beneficial Owner/surviving joint tenant/surviving tenant by the entirety/trustee of a trust] of [Name of deceased Beneficial Owner] and has delivered to the undersigned a request for redemption in form satisfactory to the undersigned, requesting that $__________ principal amount of said Notes be redeemed pursuant to said Indenture. The documents accompanying such request, all of which are in proper form, are in all respects satisfactory to the undersigned and the [Name of Representative] is entitled to have the Notes to which this Request relates redeemed.

4. The Participant holds the interest in the Notes with respect to which this Redemption Request is being made on behalf of [Name of deceased Beneficial Owner].

5. The Participant hereby certifies that it will indemnify and hold harmless the Depository, the Trustee and the Corporation (including their respective officers, directors, agents, attorneys and employees), against all damages, loss, cost, expense (including reasonable attorneys' and accountants' fees), obligations, claims or liability (collectively, the "Damages") incurred by the indemnified party or parties as a result of or in connection with the redemption of Notes to which this Request relates. The Participant will, at the request of the Corporation, forward to the Corporation, a copy of the documents submitted by [Name of Representative] in support of the request for redemption.

IN WITNESS WHEREOF, the undersigned has executed this Redemption Request as of __________
________, ________.

[PARTICIPANT NAME]

By:________________________________

Name:______________________________

Title:_______________________________

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APPENDIX B

FORM OF POLICY

Ambac

Ambac Assurance Corporation
One State Street Plaza, 15th Floor
New York, New York 10004
Telephone: (212) 668-0340

Financial Guaranty Insurance Policy

Obligor: Policy Number:

Obligations: Premium:

Ambac Assurance Corporation (Ambac), a Wisconsin stock insurance corporation, in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to The Bank of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of the Holders, that portion of the principal of and interest on the above-described obligations (the "Obligations") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor.

Ambac will make such payments to the Insurance Trustee within one (1) business day following written notification to Ambac of Nonpayment. Upon a Holder's presentation and surrender to the Insurance Trustee of such unpaid Obligations or related coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Holder the amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, Ambac shall become the owner of the surrendered Obligations and/or coupons and shall be fully subrogated to all of the Holder's rights to payment thereon.

In cases where the Obligations are issued in registered form, the Insurance Trustee shall disburse principal to a Holder only upon presentation and surrender to the Insurance Trustee of the unpaid Obligation, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee duly executed by the Holder or such Holder's duly authorized representative, so as to permit ownership of such Obligation to be registered in the name of Ambac or its nominee. The Insurance Trustee shall disburse interest to a Holder of a registered Obligation only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Obligation and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee, duly executed by the Holder or such Holder's duly authorized representative, transferring to Ambac all rights under such Obligation to receive the interest in respect of which the insurance disbursement was made. Ambac shall be subrogated to all of the Holders' rights to payment on registered Obligations to the extent of any insurance disbursements so made.

In the event that a trustee or paying agent for the Obligations has notice that any payment of principal of or interest on an Obligation which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from the Holder pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such Holder will be entitled to payment from Ambac to the extent of such recovery if sufficient funds are not otherwise available.

As used herein, the term "Holder" means any person other than (i) the Obligor or (ii) any person whose obligations constitute the underlying security or source of payment for the Obligations who, at the time of Nonpayment, is the owner of an Obligation or of a coupon relating to an Obligation. As used herein, "Due for Payment", when referring to the principal of Obligations, is when the scheduled maturity date or mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity; and, when referring to interest on the Obligations, is when the scheduled date for payment of interest has been reached. As used herein, "Nonpayment" means the failure of the Obligor to have provided sufficient funds to the trustee or paying agent for payment in full of all principal of and interest on the Obligations which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Obligations prior to maturity. This Policy does not insure against loss of any prepayment or other acceleration payment which at any time may become due in respect of any Obligation, other than at the sole option of Ambac, nor against any risk other than Nonpayment.

In witness whereof, Ambac has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

AMBAC ASSURANCE CORPORATION
CORPORATE
SEAL
WISCONSIN

President

Secretary

Effective Date:

Authorized Representative

THE BANK OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Authorized Officer of Insurance Trustee

Form No.: 2B-0012 (1/01)

Ambac

Ambac Assurance Corporation
One State Street Plaza, 15th Floor
New York, New York 10004
Telephone: (212) 668-0340

Endorsement

Policy for:

Attached to and forming part of Policy No.:

Effective Date of Endorsement:

Notwithstanding the terms and provisions contained in this Policy, it is further understood that the term "Due for Payment" shall also mean, when referring to the principal of and interest on an Obligation, any date on which such Obligation shall be subject to redemption by the Obligor upon the request of a representative of a deceased Holder pursuant to Section 4.01 of the Indenture, dated as of March 1, 2006, between the Obligor and The Bank of New York Trust Company, N.A. as trustee.

Nothing herein contained shall be held to vary, alter, waive or extend any of the terms, conditions, provisions, agreements or limitations of the above mentioned Policy other than as above stated.

In Witness Whereof, Ambac has caused this Endorsement to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

AMBAC ASSURANCE CORPORATION

President

Secretary

Authorized Representative

DELTA NATURAL GAS COMPANY, INC.

$40,000,000

5.75% Insured Quarterly Notes (IQ Notes℠) due April 1, 2021

PROSPECTUS

Edward Jones

The date of this prospectus is April 3, 2006.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(q)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.

Response:

See Tab 38 for the Annual Reports to Shareholders for the years ended June 30, 2008 and 2009. Delta does not publish a statistical supplement, but some statistical information is included on page 8 of the 2009 Annual Report under Tab 38.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(r)
Sponsoring Witness: Matthew Wesolosky

Description of Filing Requirement:

The monthly managerial reports providing financial results of operations for the twelve (12) months in the test period.

Response:

See attached.

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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement-Delta Natural FERC REG

January 01, 2009 - January 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	7,113,396.06CR	5,993,092.96CR	7,113,396.06CR	830,200.00CR	5,993,092.96CR	35,678,578.52CR	28,757,030.79CR
Small Commercial	2,278,498.84CR	1,867,659.83CR	2,278,498.84CR	244,200.00CR	1,867,659.83CR	10,734,169.82CR	8,581,755.47CR
Other Commercial	2,675,523.41CR	2,104,316.80CR	2,675,523.41CR	1,219,700.00CR	2,104,316.80CR	14,515,860.82CR	11,207,727.94CR
Industrial	316,061.32CR	261,848.86CR	316,061.32CR	.00	261,848.86CR	1,493,619.87CR	1,265,764.97CR
Unmetered Gas Light	622.32CR	612.77CR	622.32CR	700.00CR	612.77CR	8,495.88CR	7,914.69CR
Residential WNA	141,002.03	69,330.58CR	141,002.03	.00	69,330.58CR	430,065.97	358,705.31CR
Small Non-Residential WNA	39,552.75	21,516.27CR	39,552.75	.00	21,516.27CR	132,509.88	92,465.05CR
Weather Normalization Revenu	180,554.78	90,846.85CR	180,554.78	.00	90,846.85CR	562,575.85	451,170.36CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Demand-Side Revenue	1,049.00	.00	1,049.00	.00	.00	.00	.00
Total General Service Ra	12,202,498.17CR	10,318,378.07CR	12,202,498.17CR	2,294,800.00CR	10,318,378.07CR	61,868,149.06CR	50,271,364.22CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Interuptible Rate Billed							
Commercial	6,658.66CR	6,762.62CR	6,658.66CR	.00	6,762.62CR	38,607.52CR	34,663.03CR
Industrial	89,288.89CR	85,433.98CR	89,288.89CR	11,300.00CR	85,433.98CR	428,771.16CR	387,739.78CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Total Interruptible Rate	95,947.55CR	92,196.60CR	95,947.55CR	11,300.00CR	92,196.60CR	467,378.68CR	422,402.81CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Total Gas Revenue	12,298,445.72CR	10,410,574.67CR	12,298,445.72CR	2,306,100.00CR	10,410,574.67CR	62,335,527.74CR	50,693,767.03CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Miscellaneous Operating Revenue	23,655.00CR	24,585.00CR	23,655.00CR	27,300.00CR	24,585.00CR	345,415.00CR	250,306.00CR
Off System Transportation Reven	335,841.39CR	385,872.66CR	335,841.39CR	271,500.00CR	385,872.66CR	4,009,724.08CR	3,640,791.30CR
On System Transportation Revenu	475,242.88CR	523,954.13CR	475,242.88CR	274,300.00CR	523,954.13CR	4,421,242.84CR	4,308,262.35CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
TOTAL OPERATING REVENUE	13,133,184.99CR	11,344,986.46CR	13,133,184.99CR	2,879,200.00CR	11,344,986.46CR	71,111,909.66CR	58,893,126.68CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
OPERATING EXPENSES							
Purchased Gas	8,515,837.52	6,975,272.56	8,515,837.52	1,244,500.00	6,975,272.56	41,157,281.97	31,361,918.62
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Purchased Gas, net	8,515,837.52	6,975,272.56	8,515,837.52	1,244,500.00	6,975,272.56	41,157,281.97	31,361,918.62
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Operation Expense							
Labor	571,686.17	538,753.58	571,686.17	555,500.00	538,753.58	7,239,511.57	6,982,221.19
Transportation	89,161.80	74,477.36	89,161.80	78,900.00	74,477.36	965,994.91	821,558.60

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DELTA NATURAL GAS CO., INC. SUBSIDIARIES

Income Statement - Delta

January 01, 2009 - January 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	38,407.97	49,543.08	38,407.97	43,000.00	49,543.08	770,641.62	611,805.47
Customer Billing	26,906.05	14,518.50	26,906.05	27,400.00	14,518.50	305,357.69	240,551.04
Uncollectible Accounts	34,000.00	50,700.00	34,000.00	4,500.00	50,700.00	1,069,244.83	202,792.55
Administrative	48,929.49	56,490.87	48,929.49	49,300.00	56,490.87	573,590.13	561,046.97
Outside Services	89,292.31	81,183.27	89,292.31	66,400.00	81,183.27	841,190.82	773,380.66
Insurance	73,219.61	68,027.73	73,219.61	69,800.00	68,027.73	783,052.73	812,372.42
Employee Benefits	226,589.46	188,146.06	226,589.46	292,700.00	188,146.06	2,637,339.90	2,612,041.79
General Administration	64,791.80	82,379.74	64,791.80	39,300.00	82,379.74	772,724.78	731,248.05
Expenses Transferred	238,826.79CR	256,436.64CR	238,826.79CR	237,600.00CR	256,436.64CR	3,493,163.47CR	3,649,210.85CR
Other	28,710.94	25,154.46	28,710.94	61,100.00	25,154.46	432,566.93	470,600.09
Total Operation Expense	1,052,868.81	972,938.01	1,052,868.81	1,050,300.00	972,938.01	12,898,052.44	11,170,407.98
Maintenance Expense							
Labor	5,023.50	9,270.78	5,023.50	.00	9,270.78	110,862.16	120,258.61
Transportation	1,653.06	3,247.80	1,653.06	.00	3,247.80	47,719.83	42,694.37
Mains	1,831.66	7,634.69	1,831.66	6,000.00	7,634.69	132,114.27	161,102.73
Meter & Regulators	2,032.15	12,702.96	2,032.15	4,000.00	12,702.96	41,396.38	61,593.77
Other	40,116.85	77,031.00	40,116.85	42,600.00	77,031.00	554,507.35	484,758.11
Total Maintenance Expens	50,657.22	109,887.23	50,657.22	52,600.00	109,887.23	886,599.99	870,407.59
Depreciation Expense	312,048.94	300,164.36	312,048.94	315,000.00	300,164.36	3,674,359.69	4,602,045.57
Taxes Other Than Income Taxes							
Property Taxes	107,244.00	110,588.00	107,244.00	104,900.00	110,588.00	1,200,794.01	1,253,418.00
Payroll Taxes	57,867.12	54,600.46	57,867.12	49,000.00	54,600.46	588,328.93	574,650.65
Total Other Taxes	165,111.12	165,188.46	165,111.12	153,900.00	165,188.46	1,789,122.94	1,828,068.65
Income Taxes							
Current Federal	1,029,150.00	930,050.00	1,029,150.00	125,600.00CR	930,050.00	113,499.00	442,903.00CR
Current State	.00	.00	.00	.00	.00	177,514.00	125,062.00CR
Deferred Federal & State	5,350.00CR	5,350.00CR	5,350.00CR	.00	5,350.00CR	1,760,831.00	2,193,762.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	34,341.65CR	36,300.00CR
Total Income Taxes	1,021,025.00	921,716.67	1,021,025.00	125,600.00CR	921,716.67	2,017,502.35	1,589,497.00
TOTAL OPERATING EXPENSES	11,117,548.61	9,445,167.29	11,117,548.61	2,690,700.00	9,445,167.29	62,422,919.38	51,422,345.41

DELTA NATURAL GAS CO., INC ƷUBSIDIARIES

Income Statement - Delta

January 01, 2009 - January 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	2,015,636.38CR	1,899,819.17CR	2,015,636.38CR	188,500.00CR	1,899,819.17CR	8,688,990.28CR	7,470,781.27CR
Income Before Interest Charges	2,015,636.38CR	1,899,819.17CR	2,015,636.38CR	188,500.00CR	1,899,819.17CR	8,688,990.28CR	7,470,781.27CR
INTEREST CHARGES							
Interest On Long-Term Debt	304,384.24	306,328.33	304,384.24	303,200.00	306,328.33	3,666,739.04	3,684,878.03
Interest On Short-Term Debt	8,490.52CR	47,221.66	8,490.52CR	55,300.00	47,221.66	280,737.96	431,881.72
Other Interest	2,924.29	2,937.14	2,924.29	3,100.00	2,937.14	33,130.02	32,160.43
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,265.56	387,264.56
Total Interest Charges	331,089.89	388,759.01	331,089.89	393,900.00	388,759.01	4,367,872.58	4,536,184.74
NET INCOME	1,684,546.49CR	1,511,060.16CR	1,684,546.49CR	205,400.00	1,511,060.16CR	4,321,117.70CR	2,934,596.53CR

DELTA NATURAL GAS CO., INC SUBSIDIARIES

Income Statement-Delta Natural FERC REG

February 01, 2009 - February 28, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	4,734,405.69CR	4,990,556.09CR	4,734,405.69CR	830,200.00CR	4,990,556.09CR	35,422,428.12CR	28,654,772.54CR
Small Commercial	1,482,769.34CR	1,522,801.23CR	1,482,769.34CR	244,200.00CR	1,522,801.23CR	10,694,137.93CR	8,520,012.33CR
Other Commercial	1,774,580.17CR	1,786,166.46CR	1,774,580.17CR	1,219,700.00CR	1,786,166.46CR	14,504,274.53CR	11,140,462.46CR
Industrial	205,004.09CR	232,788.78CR	205,004.09CR	.00	232,788.78CR	1,465,835.18CR	1,248,932.53CR
Unmetered Gas Light	548.78CR	635.10CR	548.78CR	700.00CR	635.10CR	8,409.56CR	7,955.83CR
Residential WNA	27,868.58CR	37,218.71	27,868.58CR	.00	37,218.71	364,978.68	178,759.53CR
Small Non-Residential WNA	8,551.90CR	14,998.23	8,551.90CR	.00	14,998.23	108,959.75	47,611.78CR
Weather Normalization Revenu	36,420.48CR	52,216.94	36,420.48CR	.00	52,216.94	473,938.43	226,371.31CR
Demand-Side Revenue	228.81CR	.00	228.81CR	.00	.00	228.81CR	.00
Total General Service Ra	8,233,957.36CR	8,480,730.72CR	8,233,957.36CR	2,294,800.00CR	8,480,730.72CR	61,621,375.70CR	49,798,507.00CR
Interuptible Rate Billed							
Commercial	5,748.10CR	6,881.07CR	5,748.10CR	.00	6,881.07CR	37,474.55CR	35,351.19CR
Industrial	63,746.18CR	69,521.56CR	63,746.18CR	11,300.00CR	69,521.56CR	422,995.78CR	383,358.43CR
Total Interruptible Rate	69,494.28CR	76,402.63CR	69,494.28CR	11,300.00CR	76,402.63CR	460,470.33CR	418,709.62CR
Total Gas Revenue	8,303,451.64CR	8,557,133.35CR	8,303,451.64CR	2,306,100.00CR	8,557,133.35CR	62,081,846.03CR	50,217,216.62CR
Miscellaneous Operating Revenue	20,940.00CR	24,425.00CR	20,940.00CR	27,300.00CR	24,425.00CR	341,930.00CR	250,797.00CR
Off System Transportation Reven	306,120.06CR	378,642.87CR	306,120.06CR	271,500.00CR	378,642.87CR	3,937,201.27CR	3,696,693.83CR
On System Transportation Revenu	405,419.05CR	449,477.45CR	405,419.05CR	274,300.00CR	449,477.45CR	4,377,184.44CR	4,306,216.58CR
TOTAL OPERATING REVENUE	9,035,930.75CR	9,409,678.67CR	9,035,930.75CR	2,879,200.00CR	9,409,678.67CR	70,738,161.74CR	58,470,924.03CR
OPERATING EXPENSES							
Purchased Gas	5,867,355.97	5,709,118.67	5,867,355.97	1,244,500.00	5,709,118.67	41,315,519.27	30,859,780.91
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	5,867,355.97	5,709,118.67	5,867,355.97	1,244,500.00	5,709,118.67	41,315,519.27	30,859,780.91
Operation Expense							
Labor	529,956.42	541,888.89	529,956.42	555,500.00	541,888.89	7,227,579.10	7,000,924.17
Transportation	49,143.20	74,263.16	49,143.20	78,900.00	74,263.16	940,874.95	833,713.86

DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

February 01, 2009 - February 28, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	34,663.38	109,975.82	34,663.38	43,000.00	109,975.82	695,329.18	653,569.22
Customer Billing	35,032.53	23,202.24	35,032.53	27,400.00	23,202.24	317,187.98	244,136.77
Uncollectible Accounts	80,000.00	50,700.00	80,000.00	4,500.00	50,700.00	1,098,544.83	210,492.55
Administrative	55,636.69	53,498.61	55,636.69	49,300.00	53,498.61	575,728.21	571,687.79
Outside Services	64,641.33	75,056.14	64,641.33	66,400.00	75,056.14	830,776.01	806,290.87
Insurance	70,508.23	67,307.08	70,508.23	69,800.00	67,307.08	786,253.88	814,106.90
Employee Benefits	154,898.38	170,360.96	154,898.38	292,700.00	170,360.96	2,621,877.32	2,568,696.38
General Administration	114,899.66	150,922.60	114,899.66	39,300.00	150,922.60	736,701.84	742,604.71
Expenses Transferred	251,011.77CR	235,134.69CR	251,011.77CR	237,600.00CR	235,134.69CR	3,509,040.55CR	3,668,049.61CR
Other	17,355.78	21,098.39	17,355.78	61,100.00	21,098.39	428,824.32	476,091.89
Total Operation Expense	955,723.83	1,103,139.20	955,723.83	1,050,300.00	1,103,139.20	12,750,637.07	11,254,265.50
Maintenance Expense							
Labor	8,801.00	7,143.80	8,801.00	.00	7,143.80	112,519.36	119,635.29
Transportation	2,308.44	2,239.61	2,308.44	.00	2,239.61	47,788.66	42,440.69
Mains	4,221.45	3,487.99	4,221.45	6,000.00	3,487.99	132,847.73	160,848.28
Meter & Regulators	900.79	2,760.24	900.79	4,000.00	2,760.24	39,536.93	56,954.04
Other	16,095.81	52,607.59CR	16,095.81	42,600.00	52,607.59CR	623,210.75	401,195.58
Total Maintenance Expens	32,327.49	36,975.95CR	32,327.49	52,600.00	36,975.95CR	955,903.43	781,073.88
Depreciation Expense	311,590.79	300,204.22	311,590.79	315,000.00	300,204.22	3,685,746.26	4,467,394.37
Taxes Other Than Income Taxes							
Property Taxes	107,415.00	113,230.00	107,415.00	104,900.00	113,230.00	1,194,979.01	1,256,555.00
Payroll Taxes	56,695.90	52,204.12	56,695.90	49,000.00	52,204.12	592,820.71	575,327.21
Total Other Taxes	164,110.90	165,434.12	164,110.90	153,900.00	165,434.12	1,787,799.72	1,831,882.21
Income Taxes							
Current Federal	518,850.00	683,650.00	518,850.00	125,600.00CR	683,650.00	51,301.00CR	392,253.00CR
Current State	.00	.00	.00	.00	.00	177,514.00	125,062.00CR
Deferred Federal & State	5,350.00CR	5,350.00CR	5,350.00CR	.00	5,350.00CR	1,760,831.00	2,193,512.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	34,133.32CR	36,200.00CR
Total Income Taxes	510,725.00	675,316.67	510,725.00	125,600.00CR	675,316.67	1,852,910.68	1,639,997.00
TOTAL OPERATING EXPENSES	7,841,833.98	7,916,236.93	7,841,833.98	2,690,700.00	7,916,236.93	62,348,516.43	50,834,393.87

DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

February 01, 2009 - February 28, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	1,194,096.77CR	1,493,441.74CR	1,194,096.77CR	188,500.00CR	1,493,441.74CR	8,389,645.31CR	7,636,530.16CR
Income Before Interest Charges	1,194,096.77CR	1,493,441.74CR	1,194,096.77CR	188,500.00CR	1,493,441.74CR	8,389,645.31CR	7,636,530.16CR
INTEREST CHARGES							
Interest On Long-Term Debt	302,600.00	306,300.00	302,600.00	303,200.00	306,300.00	3,663,039.04	3,683,578.03
Interest On Short-Term Debt	6,414.93	16,014.04	6,414.93	55,300.00	16,014.04	271,138.85	435,789.58
Other Interest	3,044.35	2,996.40	3,044.35	3,100.00	2,996.40	33,177.97	32,258.99
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,265.56	387,264.56
Total Interest Charges	344,331.16	357,582.32	344,331.16	393,900.00	357,582.32	4,354,621.42	4,538,891.16
NET INCOME	849,765.61CR	1,135,859.42CR	849,765.61CR	205,400.00	1,135,859.42CR	4,035,023.89CR	3,097,639.00CR

DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement-Delta Natural FERC REG

March 01, 2009 - March 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	3,627,483.34CR	4,064,509.94CR	3,627,483.34CR	830,200.00CR	4,064,509.94CR	34,985,401.52CR	29,766,338.11CR
Small Commercial	1,050,866.71CR	1,200,617.62CR	1,050,866.71CR	244,200.00CR	1,200,617.62CR	10,544,387.02CR	8,885,223.36CR
Other Commercial	1,421,197.84CR	1,502,139.25CR	1,421,197.84CR	1,219,700.00CR	1,502,139.25CR	14,423,333.12CR	11,710,957.43CR
Industrial	149,854.80CR	173,227.11CR	149,854.80CR	.00	173,227.11CR	1,442,462.87CR	1,306,836.29CR
Unmetered Gas Light	548.78CR	635.10CR	548.78CR	700.00CR	635.10CR	8,323.24CR	7,996.97CR
Residential WNA	107,959.81CR	55,685.40	107,959.81CR	.00	55,685.40	201,333.47	382,218.41CR
Small Non-Residential WNA	30,996.61CR	14,815.62	30,996.61CR	.00	14,815.62	63,147.52	101,023.35CR
Weather Normalization Revenu	138,956.42CR	70,501.02	138,956.42CR	.00	70,501.02	264,480.99	483,241.76CR
Demand-Side Revenue	171.83CR	.00	171.83CR	.00	.00	400.64CR	.00
Total General Service Ra	6,389,079.72CR	6,870,628.00CR	6,389,079.72CR	2,294,800.00CR	6,870,628.00CR	61,139,827.42CR	52,160,593.92CR
Interuptible Rate Billed							
Commercial	5,591.35CR	5,944.82CR	5,591.35CR	.00	5,944.82CR	37,121.08CR	37,120.80CR
Industrial	37,331.16CR	45,461.89CR	37,331.16CR	11,300.00CR	45,461.89CR	414,865.05CR	399,509.19CR
Total Interruptible Rate	42,922.51CR	51,406.71CR	42,922.51CR	11,300.00CR	51,406.71CR	451,986.13CR	436,629.99CR
Total Gas Revenue	6,432,002.23CR	6,922,034.71CR	6,432,002.23CR	2,306,100.00CR	6,922,034.71CR	61,591,813.55CR	52,597,223.91CR
Miscellaneous Operating Revenue	26,145.00CR	25,845.00CR	26,145.00CR	27,300.00CR	25,845.00CR	342,230.00CR	262,841.00CR
Off System Transportation Reven	342,763.65CR	372,850.83CR	342,763.65CR	271,500.00CR	372,850.83CR	3,907,114.09CR	3,722,390.32CR
On System Transportation Revenu	354,657.14CR	432,073.05CR	354,657.14CR	274,300.00CR	432,073.05CR	4,299,768.53CR	4,372,388.63CR
TOTAL OPERATING REVENUE	7,155,568.02CR	7,752,803.59CR	7,155,568.02CR	2,879,200.00CR	7,752,803.59CR	70,140,926.17CR	60,954,843.86CR
OPERATING EXPENSES							
Purchased Gas	4,108,378.70	4,514,085.94	4,108,378.70	1,244,500.00	4,514,085.94	40,909,812.03	32,690,501.07
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	4,108,378.70	4,514,085.94	4,108,378.70	1,244,500.00	4,514,085.94	40,909,812.03	32,690,501.07
Operation Expense							
Labor	588,239.77	611,044.50	588,239.77	555,500.00	611,044.50	7,204,774.37	7,003,769.45
Transportation	77,435.44	105,485.64	77,435.44	78,900.00	105,485.64	912,824.75	840,410.72

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DELTA NATURAL GAS CO., INC. [illegible]UBSIDIARIES

Income Statement - Delta

March 01, 2009 - March 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	47,067.59	83,175.55	47,067.59	43,000.00	83,175.55	659,221.22	650,358.98
Customer Billing	22,827.38	33,910.30	22,827.38	27,400.00	33,910.30	306,105.06	259,251.54
Uncollectible Accounts	50,000.00	152,000.00	50,000.00	4,500.00	152,000.00	996,544.83	319,492.55
Administrative	40,285.69	43,422.55	40,285.69	49,300.00	43,422.55	572,591.35	560,115.87
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Outside Services	105,131.18	49,050.20	105,131.18	66,400.00	49,050.20	886,856.99	771,839.90
Insurance	71,956.88	62,549.10	71,956.88	69,800.00	62,549.10	795,661.66	811,390.80
Employee Benefits	233,788.43	91,607.50	233,788.43	292,700.00	91,607.50	2,764,058.25	2,391,952.98
General Administration	78,758.29	40,161.87	78,758.29	39,300.00	40,161.87	775,298.26	739,395.04
Expenses Transferred	276,171.25CR	238,305.36CR	276,171.25CR	237,600.00CR	238,305.36CR	3,546,906.44CR	3,690,352.70CR
Other	38,134.54	31,729.17	38,134.54	61,100.00	31,729.17	435,229.69	470,156.35
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Total Operation Expense	1,077,453.94	1,065,831.02	1,077,453.94	1,050,300.00	1,065,831.02	12,762,259.99	11,127,781.48
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Maintenance Expense							
Labor	4,502.92	8,988.02	4,502.92	.00	8,988.02	108,034.26	115,317.61
Transportation	2,046.53	5,748.93	2,046.53	.00	5,748.93	44,086.26	42,091.68
Mains	22,629.89	6,279.64	22,629.89	6,000.00	6,279.64	149,197.98	161,001.25
Meter & Regulators	9,138.72	9,518.12	9,138.72	4,000.00	9,518.12	39,157.53	60,155.73
Other	48,109.85	27,930.48	48,109.85	42,600.00	27,930.48	643,390.12	405,348.77
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Total Maintenance Expens	86,427.91	58,465.19	86,427.91	52,600.00	58,465.19	983,866.15	783,915.04
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Depreciation Expense	312,492.62	299,379.26	312,492.62	315,000.00	299,379.26	3,698,859.62	4,385,262.67
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Taxes Other Than Income Taxes							
Property Taxes	110,184.00	110,230.00	110,184.00	104,900.00	110,230.00	1,194,933.01	1,260,242.00
Payroll Taxes	51,423.32	49,154.04	51,423.32	49,000.00	49,154.04	595,089.99	577,744.05
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Total Other Taxes	161,607.32	159,384.04	161,607.32	153,900.00	159,384.04	1,790,023.00	1,837,986.05
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Income Taxes							
Current Federal	385,900.00	487,773.00	385,900.00	125,600.00CR	487,773.00	153,174.00CR	98,680.00CR
Current State	.00	.00	.00	.00	.00	177,514.00	125,062.00CR
Deferred Federal & State	5,350.00CR	5,350.00CR	5,350.00CR	.00	5,350.00CR	1,760,831.00	2,193,262.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	33,924.99CR	36,100.00CR
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Total Income Taxes	377,775.00	479,439.67	377,775.00	125,600.00CR	479,439.67	1,751,246.01	1,933,420.00
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TOTAL OPERATING EXPENSES	6,124,135.49	6,576,585.12	6,124,135.49	2,690,700.00	6,576,585.12	61,896,066.80	52,758,866.31
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DELTA NATURAL GAS CO., INC. ᴊUBSIDIARIES

Income Statement - Delta

March 01, 2009 - March 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	1,031,432.53CR	1,176,218.47CR	1,031,432.53CR	188,500.00CR	1,176,218.47CR	8,244,859.37CR	8,195,977.55CR
Income Before Interest Charges	1,031,432.53CR	1,176,218.47CR	1,031,432.53CR	188,500.00CR	1,176,218.47CR	8,244,859.37CR	8,195,977.55CR
INTEREST CHARGES							
Interest On Long-Term Debt	302,847.71	306,356.88	302,847.71	303,200.00	306,356.88	3,659,529.87	3,682,419.28
Interest On Short-Term Debt	4,594.56	9,182.84	4,594.56	55,300.00	9,182.84	266,550.57	452,941.36
Other Interest	3,024.53	3,065.52	3,024.53	3,100.00	3,065.52	33,136.98	32,444.13
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,265.56	387,264.56
Total Interest Charges	342,738.68	350,877.12	342,738.68	393,900.00	350,877.12	4,346,482.98	4,555,069.33
NET INCOME	688,693.85CR	825,341.35CR	688,693.85CR	205,400.00	825,341.35CR	3,898,376.39CR	3,640,908.22CR

DELTA NATURAL GAS CO., INC. /BSIDIARIES

Income Statement-Delta Natural FERC REG

April 01, 2009 - April 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	1,674,954.03CR	2,267,083.74CR	1,674,954.03CR	830,200.00CR	2,267,083.74CR	34,393,271.81CR	29,745,531.86CR
Small Commercial	453,055.86CR	619,377.62CR	453,055.86CR	244,200.00CR	619,377.62CR	10,378,065.26CR	8,862,972.63CR
Other Commercial	688,908.34CR	918,649.96CR	688,908.34CR	1,219,700.00CR	918,649.96CR	14,193,591.50CR	11,699,597.58CR
Industrial	55,284.75CR	87,893.38CR	55,284.75CR	.00	87,893.38CR	1,409,854.24CR	1,288,757.87CR
Unmetered Gas Light	548.78CR	635.10CR	548.78CR	700.00CR	635.10CR	8,236.92CR	8,038.11CR
Residential WNA	6,250.60CR	3,800.41	6,250.60CR	.00	3,800.41	191,282.46	134,604.03CR
Small Non-Residential WNA	1,977.27CR	1,030.25	1,977.27CR	.00	1,030.25	60,140.00	40,607.40CR
Weather Normalization Revenu	8,227.87CR	4,830.66	8,227.87CR	.00	4,830.66	251,422.46	175,211.43CR
Demand-Side Revenue	100.93CR	.00	100.93CR	.00	.00	501.57CR	.00
Total General Service Ra	2,881,080.56CR	3,888,809.14CR	2,881,080.56CR	2,294,800.00CR	3,888,809.14CR	60,132,098.84CR	51,780,109.48CR
Interuptible Rate Billed							
Commercial	2,321.02CR	2,573.03CR	2,321.02CR	.00	2,573.03CR	36,869.07CR	35,021.71CR
Industrial	12,031.83CR	21,521.77CR	12,031.83CR	11,300.00CR	21,521.77CR	405,375.11CR	395,438.73CR
Total Interruptible Rate	14,352.85CR	24,094.80CR	14,352.85CR	11,300.00CR	24,094.80CR	442,244.18CR	430,460.44CR
Total Gas Revenue	2,895,433.41CR	3,912,903.94CR	2,895,433.41CR	2,306,100.00CR	3,912,903.94CR	60,574,343.02CR	52,210,569.92CR
Miscellaneous Operating Revenue	37,815.00CR	42,465.00CR	37,815.00CR	27,300.00CR	42,465.00CR	337,580.00CR	276,428.00CR
Off System Transportation Reven	243,979.56CR	298,594.62CR	243,979.56CR	271,500.00CR	298,594.62CR	3,852,499.03CR	3,670,267.30CR
On System Transportation Revenu	307,513.24CR	363,306.96CR	307,513.24CR	274,300.00CR	363,306.96CR	4,243,974.81CR	4,387,504.89CR
TOTAL OPERATING REVENUE	3,484,741.21CR	4,617,270.52CR	3,484,741.21CR	2,879,200.00CR	4,617,270.52CR	69,008,396.86CR	60,544,770.11CR
OPERATING EXPENSES							
Purchased Gas	1,796,073.36	2,665,232.07	1,796,073.36	1,244,500.00	2,665,232.07	40,040,653.32	32,690,527.01
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	1,796,073.36	2,665,232.07	1,796,073.36	1,244,500.00	2,665,232.07	40,040,653.32	32,690,527.01
Operation Expense							
Labor	532,386.06	511,906.94	532,386.06	555,500.00	511,906.94	7,225,253.49	7,008,305.59
Transportation	77,361.60	67,334.98	77,361.60	78,900.00	67,334.98	922,851.37	853,174.88

DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

April 01, 2009 - April 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	39,840.61	34,578.59	39,840.61	43,000.00	34,578.59	664,483.24	628,034.49
Customer Billing	39,070.78	18,412.87	39,070.78	27,400.00	18,412.87	326,762.97	259,114.27
Uncollectible Accounts	34,000.00	50,700.00	34,000.00	4,500.00	50,700.00	979,844.83	327,192.55
Administrative	44,124.14	40,907.42	44,124.14	49,300.00	40,907.42	575,808.07	561,957.64
Outside Services	78,915.70	66,559.96	78,915.70	66,400.00	66,559.96	899,212.73	784,735.29
Insurance	69,041.70	63,668.16	69,041.70	69,800.00	63,668.16	801,035.20	808,450.38
Employee Benefits	223,371.20	301,068.91	223,371.20	292,700.00	301,068.91	2,686,360.54	2,497,400.76
General Administration	35,615.40	43,325.70	35,615.40	39,300.00	43,325.70	767,587.96	741,312.11
Expenses Transferred	246,450.02CR	225,941.75CR	246,450.02CR	237,600.00CR	225,941.75CR	3,567,414.71CR	3,702,044.92CR
Other	879,753.63	22,809.09	879,753.63	61,100.00	22,809.09	1,292,174.23	471,122.53
Total Operation Expense	1,807,030.80	995,330.87	1,807,030.80	1,050,300.00	995,330.87	13,573,959.92	11,238,755.57
Maintenance Expense							
Labor	13,143.91	11,943.97	13,143.91	.00	11,943.97	109,234.20	114,414.57
Transportation	5,728.02	4,525.18	5,728.02	.00	4,525.18	45,289.10	42,253.36
Mains	3,977.98CR	4,905.09	3,977.98CR	6,000.00	4,905.09	140,314.91	162,204.56
Meter & Regulators	1,388.93	2,534.38	1,388.93	4,000.00	2,534.38	38,012.08	61,971.79
Other	29,026.06	63,754.99	29,026.06	42,600.00	63,754.99	608,661.19	424,740.00
Total Maintenance Expens	45,308.94	87,663.61	45,308.94	52,600.00	87,663.61	941,511.48	805,584.28
Depreciation Expense	313,064.75	302,149.42	313,064.75	315,000.00	302,149.42	3,709,774.95	4,274,599.40
Taxes Other Than Income Taxes							
Property Taxes	108,065.00	110,340.00	108,065.00	104,900.00	110,340.00	1,192,658.01	1,263,299.00
Payroll Taxes	45,050.86	44,138.79	45,050.86	49,000.00	44,138.79	596,002.06	578,481.80
Total Other Taxes	153,115.86	154,478.79	153,115.86	153,900.00	154,478.79	1,788,660.07	1,841,780.80
Income Taxes							
Current Federal	353,950.00CR	32,550.00	353,950.00CR	125,600.00CR	32,550.00	539,674.00CR	278,630.00CR
Current State	.00	.00	.00	.00	.00	177,514.00	125,062.00CR
Deferred Federal & State	5,350.00CR	5,350.00CR	5,350.00CR	.00	5,350.00CR	1,760,831.00	2,193,012.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	33,716.66CR	36,000.00CR
Total Income Taxes	362,075.00CR	24,216.67	362,075.00CR	125,600.00CR	24,216.67	1,364,954.34	1,753,320.00
TOTAL OPERATING EXPENSES	3,752,518.71	4,229,071.43	3,752,518.71	2,690,700.00	4,229,071.43	61,419,514.08	52,604,567.06

DELTA NATURAL GAS CO., INC. ,UBSIDIARIES

Income Statement - Delta

April 01, 2009 - April 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	267,777.50	388,199.09CR	267,777.50	188,500.00CR	388,199.09CR	7,588,882.78CR	7,940,203.05CR
Income Before Interest Charges	267,777.50	388,199.09CR	267,777.50	188,500.00CR	388,199.09CR	7,588,882.78CR	7,940,203.05CR
INTEREST CHARGES							
Interest On Long-Term Debt	302,440.83	306,387.50	302,440.83	303,200.00	306,387.50	3,655,583.20	3,681,181.78
Interest On Short-Term Debt	771.41	7,397.06	771.41	55,300.00	7,397.06	259,924.92	466,867.05
Other Interest	3,089.41	3,091.92	3,089.41	3,100.00	3,091.92	33,134.47	32,493.72
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,265.56	387,264.56
Total Interest Charges	338,573.53	349,148.36	338,573.53	393,900.00	349,148.36	4,335,908.15	4,567,807.11
NET INCOME	606,351.03	39,050.73CR	606,351.03	205,400.00	39,050.73CR	3,252,974.63CR	3,372,395.94CR

DELTA NATURAL GAS CO., INC SUBSIDIARIES

Income Statement-Delta Natural FERC REG

May 01, 2009 - May 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	1,053,971.83CR	1,375,330.50CR	1,053,971.83CR	830,200.00CR	1,375,330.50CR	34,071,913.14CR	30,309,157.87CR
Small Commercial	283,889.37CR	376,774.89CR	283,889.37CR	244,200.00CR	376,774.89CR	10,285,179.74CR	8,982,792.39CR
Other Commercial	493,522.43CR	675,330.36CR	493,522.43CR	1,219,700.00CR	675,330.36CR	14,011,783.57CR	11,915,037.43CR
Industrial	36,888.69CR	54,533.78CR	36,888.69CR	.00	54,533.78CR	1,392,209.15CR	1,299,901.98CR
Unmetered Gas Light	471.50CR	775.04CR	471.50CR	700.00CR	775.04CR	7,933.38CR	8,113.31CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	72.36CR	.00	72.36CR	.00	.00	573.93CR	.00
Total General Service Ra	1,868,816.18CR	2,482,744.57CR	1,868,816.18CR	2,294,800.00CR	2,482,744.57CR	59,518,170.45CR	52,690,214.41CR
Interuptible Rate Billed							
Commercial	14.31CR	239.76CR	14.31CR	.00	239.76CR	36,643.62CR	34,814.34CR
Industrial	9,817.29CR	18,804.56CR	9,817.29CR	11,300.00CR	18,804.56CR	396,387.84CR	398,343.65CR
Total Interruptible Rate	9,831.60CR	19,044.32CR	9,831.60CR	11,300.00CR	19,044.32CR	433,031.46CR	433,157.99CR
Total Gas Revenue	1,878,647.78CR	2,501,788.89CR	1,878,647.78CR	2,306,100.00CR	2,501,788.89CR	59,951,201.91CR	53,123,372.40CR
Miscellaneous Operating Revenue	39,650.00CR	44,130.00CR	39,650.00CR	27,300.00CR	44,130.00CR	333,100.00CR	295,492.00CR
Off System Transportation Reven	349,717.23CR	318,202.56CR	349,717.23CR	271,500.00CR	318,202.56CR	3,884,013.70CR	3,785,160.52CR
On System Transportation Revenu	254,154.10CR	333,961.11CR	254,154.10CR	274,300.00CR	333,961.11CR	4,164,167.80CR	4,425,037.25CR
TOTAL OPERATING REVENUE	2,522,169.11CR	3,198,082.56CR	2,522,169.11CR	2,879,200.00CR	3,198,082.56CR	68,332,483.41CR	61,629,062.17CR
OPERATING EXPENSES							
Purchased Gas	830,935.97	1,463,739.82	830,935.97	1,244,500.00	1,463,739.82	39,407,849.47	33,264,602.86
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	830,935.97	1,463,739.82	830,935.97	1,244,500.00	1,463,739.82	39,407,849.47	33,264,602.86
Operation Expense							
Labor	529,148.87	520,683.14	529,148.87	555,500.00	520,683.14	7,233,719.22	7,033,130.44
Transportation	49,655.84	92,404.30	49,655.84	78,900.00	92,404.30	880,102.91	886,184.80

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DELTA NATURAL GAS CO., INC SUBSIDIARIES

Income Statement - Delta

May 01, 2009 - May 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	39,737.78	43,338.31	39,737.78	43,000.00	43,338.31	660,882.71	629,322.23
Customer Billing	31,865.49	15,187.44	31,865.49	27,400.00	15,187.44	343,441.02	249,613.25
Uncollectible Accounts	34,000.00	176,446.00	34,000.00	4,500.00	176,446.00	837,398.83	460,638.55
Administrative	46,456.32	51,352.25	46,456.32	49,300.00	51,352.25	570,912.14	567,959.54
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Outside Services	64,394.63	78,264.55	64,394.63	66,400.00	78,264.55	885,342.81	793,497.62
Insurance	70,565.69	66,349.66	70,565.69	69,800.00	66,349.66	805,251.23	806,891.68
Employee Benefits	212,722.60	224,868.10	212,722.60	292,700.00	224,868.10	2,674,215.04	2,472,313.72
General Administration	39,199.49	76,100.59	39,199.49	39,300.00	76,100.59	730,686.86	776,177.82
Expenses Transferred	244,817.03CR	225,052.44CR	244,817.03CR	237,600.00CR	225,052.44CR	3,587,179.30CR	3,701,849.11CR
Other	35,256.90	35,050.17	35,256.90	61,100.00	35,050.17	1,292,380.96	448,750.28
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Total Operation Expense	908,186.58	1,154,992.07	908,186.58	1,050,300.00	1,154,992.07	13,327,154.43	11,422,630.82
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Maintenance Expense							
Labor	7,865.11	7,078.49	7,865.11	.00	7,078.49	110,020.82	112,534.35
Transportation	2,357.52	3,271.68	2,357.52	.00	3,271.68	44,374.94	42,727.81
Mains	4,380.07	19,531.60	4,380.07	6,000.00	19,531.60	125,163.38	172,415.21
Meter & Regulators	4,759.33	1,296.92	4,759.33	4,000.00	1,296.92	41,474.49	52,318.14
Other	24,198.65	108,855.43	24,198.65	42,600.00	108,855.43	524,004.41	488,398.69
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Total Maintenance Expens	43,560.68	140,034.12	43,560.68	52,600.00	140,034.12	845,038.04	868,394.20
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Depreciation Expense	317,412.71	302,681.41	317,412.71	315,000.00	302,681.41	3,724,506.25	4,163,085.93
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Taxes Other Than Income Taxes							
Property Taxes	107,772.00	110,818.00	107,772.00	104,900.00	110,818.00	1,189,612.01	1,266,936.00
Payroll Taxes	43,173.04	42,244.66	43,173.04	49,000.00	42,244.66	596,930.44	578,981.48
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Total Other Taxes	150,945.04	153,062.66	150,945.04	153,900.00	153,062.66	1,786,542.45	1,845,917.48
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Income Taxes							
Current Federal	784,840.31	129,850.00CR	784,840.31	125,600.00CR	129,850.00CR	375,016.31	134,280.00CR
Current State	643,800.91	.00	643,800.91	.00	.00	821,314.91	125,062.00CR
Deferred Federal & State	1,160,181.48CR	5,350.00CR	1,160,181.48CR	.00	5,350.00CR	605,999.52	2,192,762.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	33,508.33CR	35,900.00CR
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Total Income Taxes	265,684.74	138,183.33CR	265,684.74	125,600.00CR	138,183.33CR	1,768,822.41	1,897,520.00
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TOTAL OPERATING EXPENSES	2,516,725.72	3,076,326.75	2,516,725.72	2,690,700.00	3,076,326.75	60,859,913.05	53,462,151.29
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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

May 01, 2009 - May 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	5,443.39CR	121,755.81CR	5,443.39CR	188,500.00CR	121,755.81CR	7,472,570.36CR	8,166,910.88CR
Income Before Interest Charges	5,443.39CR	121,755.81CR	5,443.39CR	188,500.00CR	121,755.81CR	7,472,570.36CR	8,166,910.88CR
INTEREST CHARGES							
Interest On Long-Term Debt	302,200.00	306,000.00	302,200.00	303,200.00	306,000.00	3,651,783.20	3,679,581.78
Interest On Short-Term Debt	1,038.62CR	6,705.56	1,038.62CR	55,300.00	6,705.56	252,180.74	459,867.51
Other Interest	2,850.26	2,775.43	2,850.26	3,100.00	2,775.43	33,209.30	32,551.65
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,265.56	387,264.56
Total Interest Charges	336,283.52	347,752.87	336,283.52	393,900.00	347,752.87	4,324,438.80	4,559,265.50
NET INCOME	330,840.13	225,997.06	330,840.13	205,400.00	225,997.06	3,148,131.56CR	3,607,645.38CR

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DELTA NATURAL GAS CO., INC. ,UBSIDIARIES

Income Statement-Delta Natural FERC REG

June 01, 2009 - June 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	822,704.81CR	938,112.79CR	822,704.81CR	830,200.00CR	938,112.79CR	33,956,505.16CR	30,598,471.44CR
Small Commercial	228,715.28CR	270,876.12CR	228,715.28CR	244,200.00CR	270,876.12CR	10,243,018.90CR	9,047,722.41CR
Other Commercial	387,704.98CR	493,684.08CR	387,704.98CR	1,219,700.00CR	493,684.08CR	13,905,804.47CR	12,047,962.83CR
Industrial	26,991.09CR	40,354.70CR	26,991.09CR	.00	40,354.70CR	1,378,845.54CR	1,305,284.58CR
Unmetered Gas Light	430.50CR	747.36CR	430.50CR	700.00CR	747.36CR	7,616.52CR	8,160.83CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	20.39CR	.00	20.39CR	.00	.00	594.32CR	.00
Total General Service Ra	1,466,567.05CR	1,743,775.05CR	1,466,567.05CR	2,294,800.00CR	1,743,775.05CR	59,240,962.45CR	53,182,813.52CR
Interuptible Rate Billed							
Commercial	.00	.00	.00	.00	.00	36,643.62CR	34,807.00CR
Industrial	9,583.15CR	15,408.48CR	9,583.15CR	11,300.00CR	15,408.48CR	390,562.51CR	401,962.60CR
Total Interruptible Rate	9,583.15CR	15,408.48CR	9,583.15CR	11,300.00CR	15,408.48CR	427,206.13CR	436,769.60CR
Total Gas Revenue	1,476,150.20CR	1,759,183.53CR	1,476,150.20CR	2,306,100.00CR	1,759,183.53CR	59,668,168.58CR	53,619,583.12CR
Miscellaneous Operating Revenue	26,135.00CR	26,865.00CR	26,135.00CR	27,300.00CR	26,865.00CR	332,370.00CR	292,538.00CR
Off System Transportation Reven	248,384.88CR	346,530.96CR	248,384.88CR	271,500.00CR	346,530.96CR	3,785,867.62CR	3,864,346.74CR
On System Transportation Revenu	262,676.75CR	308,942.13CR	262,676.75CR	274,300.00CR	308,942.13CR	4,117,902.42CR	4,460,557.54CR
TOTAL OPERATING REVENUE	2,013,346.83CR	2,441,521.62CR	2,013,346.83CR	2,879,200.00CR	2,441,521.62CR	67,904,308.62CR	62,237,025.40CR
OPERATING EXPENSES							
Purchased Gas	554,585.19	824,910.08	554,585.19	1,244,500.00	824,910.08	39,137,524.58	33,493,413.62
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	554,585.19	824,910.08	554,585.19	1,244,500.00	824,910.08	39,137,524.58	33,493,413.62
Operation Expense							
Labor	951,280.57	1,291,941.03	951,280.57	555,500.00	1,291,941.03	6,893,058.76	7,080,636.10
Transportation	59,548.40	84,669.66	59,548.40	78,900.00	84,669.66	854,981.65	906,369.90

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DELTA NATURAL GAS CO., INC. ,UBSIDIARIES

Income Statement - Delta

June 01, 2009 - June 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	43,479.94	212,470.05	43,479.94	43,000.00	212,470.05	491,892.60	801,366.28
Customer Billing	22,671.05	37,117.63	22,671.05	27,400.00	37,117.63	328,994.44	267,974.70
Uncollectible Accounts	533,412.06CR	57,601.17CR	533,412.06CR	4,500.00	57,601.17CR	361,587.94	599,344.83
Administrative	46,508.09	49,099.20	46,508.09	49,300.00	49,099.20	568,321.03	574,985.39
Outside Services	96,841.08	50,334.13	96,841.08	66,400.00	50,334.13	931,849.76	808,063.38
Insurance	66,672.49	67,473.12	66,672.49	69,800.00	67,473.12	804,450.60	809,571.09
Employee Benefits	353,834.09	247,396.89	353,834.09	292,700.00	247,396.89	2,780,652.24	2,477,579.01
General Administration	63,151.32	58,139.22	63,151.32	39,300.00	58,139.22	735,698.96	781,448.61
Expenses Transferred	526,689.00CR	889,758.89CR	526,689.00CR	237,600.00CR	889,758.89CR	3,224,109.41CR	3,524,229.63CR
Other	68,095.76	71,130.79	68,095.76	61,100.00	71,130.79	1,289,345.93	465,523.56
Total Operation Expense	711,981.73	1,222,411.66	711,981.73	1,050,300.00	1,222,411.66	12,816,724.50	12,048,633.22
Maintenance Expense							
Labor	11,169.27	14,238.49	11,169.27	.00	14,238.49	106,951.60	121,037.13
Transportation	3,539.45	6,359.24	3,539.45	.00	6,359.24	41,555.15	47,069.24
Mains	8,672.85	34,781.51	8,672.85	6,000.00	34,781.51	99,054.72	198,069.27
Meter & Regulators	10,189.16	1,943.20	10,189.16	4,000.00	1,943.20	49,720.45	49,991.59
Other	57,668.01	150,735.06	57,668.01	42,600.00	150,735.06	430,937.36	587,264.06
Total Maintenance Expens	91,238.74	208,057.50	91,238.74	52,600.00	208,057.50	728,219.28	1,003,431.29
Depreciation Expense	317,868.19	305,234.35	317,868.19	315,000.00	305,234.35	3,737,140.09	4,053,113.17
Taxes Other Than Income Taxes							
Property Taxes	129,309.00	37,154.78	129,309.00	104,900.00	37,154.78	1,281,766.23	1,197,547.78
Payroll Taxes	72,132.56	93,537.32	72,132.56	49,000.00	93,537.32	575,525.68	590,309.91
Total Other Taxes	201,441.56	130,692.10	201,441.56	153,900.00	130,692.10	1,857,291.91	1,787,857.69
Income Taxes							
Current Federal	1,906,864.85CR	1,163,810.00CR	1,906,864.85CR	125,600.00CR	1,163,810.00CR	368,038.54CR	103,800.00CR
Current State	424,287.46CR	296,340.00	424,287.46CR	.00	296,340.00	100,687.45	56,100.00
Deferred Federal & State	2,242,034.18	638,450.00	2,242,034.18	.00	638,450.00	2,209,583.70	2,074,000.00
Investment Tax Credit-Net	2,775.00CR	2,983.33CR	2,775.00CR	.00	2,983.33CR	33,300.00CR	35,800.00CR
Total Income Taxes	91,893.13CR	232,003.33CR	91,893.13CR	125,600.00CR	232,003.33CR	1,908,932.61	1,990,500.00
TOTAL OPERATING EXPENSES	1,785,222.28	2,459,302.36	1,785,222.28	2,690,700.00	2,459,302.36	60,185,832.97	54,376,948.99

DELTA NATURAL GAS CO., INC. SUBSIDIARIES

Income Statement - Delta

June 01, 2009 - June 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	228,124.55CR	17,780.74	228,124.55CR	188,500.00CR	17,780.74	7,718,475.65CR	7,860,076.41CR
Income Before Interest Charges	228,124.55CR	17,780.74	228,124.55CR	188,500.00CR	17,780.74	7,718,475.65CR	7,860,076.41CR
INTEREST CHARGES							
Interest On Long-Term Debt	302,329.17	305,869.37	302,329.17	303,200.00	305,869.37	3,648,243.00	3,677,983.44
Interest On Short-Term Debt	660.22	16,917.24	660.22	55,300.00	16,917.24	235,923.72	458,447.35
Other Interest	2,801.06	2,783.13	2,801.06	3,100.00	2,783.13	33,227.23	32,692.90
Amortization of Debt Expense	32,271.88	32,274.88	32,271.88	32,300.00	32,274.88	387,262.56	387,265.56
Total Interest Charges	338,062.33	357,844.62	338,062.33	393,900.00	357,844.62	4,304,656.51	4,556,389.25
NET INCOME	109,937.78	375,625.36	109,937.78	205,400.00	375,625.36	3,413,819.14CR	3,303,687.16CR

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DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement-Delta Natural FERC REG

July 01, 2009 - July 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	740,057.48CR	904,524.28CR	740,057.48CR	830,200.00CR	904,524.28CR	33,792,038.36CR	30,793,837.42CR
Small Commercial	213,632.67CR	279,589.14CR	213,632.67CR	244,200.00CR	279,589.14CR	10,177,062.43CR	9,095,616.34CR
Other Commercial	344,299.56CR	530,499.40CR	344,299.56CR	1,219,700.00CR	530,499.40CR	13,719,604.63CR	12,160,974.52CR
Industrial	20,030.18CR	38,968.70CR	20,030.18CR	.00	38,968.70CR	1,359,907.02CR	1,302,802.27CR
Unmetered Gas Light	389.50CR	719.68CR	389.50CR	700.00CR	719.68CR	7,286.34CR	8,246.28CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	13.92CR	.00	13.92CR	.00	.00	608.24CR	.00
Total General Service Ra	1,318,423.31CR	1,754,301.20CR	1,318,423.31CR	2,294,800.00CR	1,754,301.20CR	58,805,084.56CR	53,536,688.26CR
Interuptible Rate Billed							
Commercial	.00	.00	.00	.00	.00	36,643.62CR	34,807.00CR
Industrial	10,685.36CR	17,377.98CR	10,685.36CR	11,300.00CR	17,377.98CR	383,869.89CR	405,172.29CR
Total Interruptible Rate	10,685.36CR	17,377.98CR	10,685.36CR	11,300.00CR	17,377.98CR	420,513.51CR	439,979.29CR
Total Gas Revenue	1,329,108.67CR	1,771,679.18CR	1,329,108.67CR	2,306,100.00CR	1,771,679.18CR	59,225,598.07CR	53,976,667.55CR
Miscellaneous Operating Revenue	24,115.00CR	27,300.00CR	24,115.00CR	27,300.00CR	27,300.00CR	329,185.00CR	307,401.00CR
Off System Transportation Reven	248,222.07CR	313,389.27CR	248,222.07CR	271,500.00CR	313,389.27CR	3,720,700.42CR	3,882,261.35CR
On System Transportation Revenu	266,921.27CR	275,640.46CR	266,921.27CR	274,300.00CR	275,640.46CR	4,109,183.23CR	4,461,696.03CR
TOTAL OPERATING REVENUE	1,868,367.01CR	2,388,008.91CR	1,868,367.01CR	2,879,200.00CR	2,388,008.91CR	67,384,666.72CR	62,628,025.93CR
OPERATING EXPENSES							
Purchased Gas	529,999.56	975,595.38	529,999.56	1,244,500.00	975,595.38	38,691,928.76	33,759,863.95
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	529,999.56	975,595.38	529,999.56	1,244,500.00	975,595.38	38,691,928.76	33,759,863.95
Operation Expense							
Labor	540,189.04	543,941.69	540,189.04	555,500.00	543,941.69	6,889,306.11	7,094,197.74
Transportation	72,325.80	77,387.44	72,325.80	78,900.00	77,387.44	849,920.01	924,553.14

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DELTA NATURAL GAS CO., INC. SUBSIDIARIES

Income Statement - Delta

July 01, 2009 - July 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	42,945.11	41,047.41	42,945.11	43,000.00	41,047.41	493,790.30	806,897.70
Customer Billing	20,834.52	21,509.48	20,834.52	27,400.00	21,509.48	328,319.48	261,189.91
Uncollectible Accounts	.00	.00	.00	4,500.00	.00	361,587.94	599,344.83
Administrative	45,309.15	43,904.03	45,309.15	49,300.00	43,904.03	569,726.15	580,473.58
Outside Services	73,075.53	84,222.56	73,075.53	66,400.00	84,222.56	920,702.73	843,123.38
Insurance	70,028.54	63,698.00	70,028.54	69,800.00	63,698.00	810,781.14	805,194.56
Employee Benefits	280,164.13	200,722.62	280,164.13	292,700.00	200,722.62	2,860,093.75	2,525,072.47
General Administration	34,025.19	33,796.52	34,025.19	39,300.00	33,796.52	735,927.63	785,947.78
Expenses Transferred	265,957.45CR	242,419.12CR	265,957.45CR	237,600.00CR	242,419.12CR	3,247,647.74CR	3,531,329.95CR
Other	39,660.59	34,035.22	39,660.59	61,100.00	34,035.22	1,294,971.30	465,851.84
Total Operation Expense	952,600.15	901,845.85	952,600.15	1,050,300.00	901,845.85	12,867,478.80	12,160,516.98
Maintenance Expense							
Labor	7,536.06	10,924.27	7,536.06	.00	10,924.27	103,563.39	124,333.14
Transportation	2,907.01	4,533.81	2,907.01	.00	4,533.81	39,928.35	49,427.65
Mains	4,595.04	23,978.43	4,595.04	6,000.00	23,978.43	79,671.33	219,252.15
Meter & Regulators	2,485.08	2,223.47	2,485.08	4,000.00	2,223.47	49,982.06	49,776.53
Other	19,519.63	57,082.52	19,519.63	42,600.00	57,082.52	393,374.47	610,967.94
Total Maintenance Expens	37,042.82	98,742.50	37,042.82	52,600.00	98,742.50	666,519.60	1,053,757.41
Depreciation Expense	318,384.85	306,187.95	318,384.85	315,000.00	306,187.95	3,749,336.99	3,951,572.43
Taxes Other Than Income Taxes							
Property Taxes	110,497.00	105,437.00	110,497.00	104,900.00	105,437.00	1,286,826.23	1,198,952.78
Payroll Taxes	45,509.85	48,299.83	45,509.85	49,000.00	48,299.83	572,735.70	594,255.06
Total Other Taxes	156,006.85	153,736.83	156,006.85	153,900.00	153,736.83	1,859,561.93	1,793,207.84
Income Taxes							
Current Federal	203,260.74CR	152,450.00CR	203,260.74CR	125,600.00CR	152,450.00CR	418,849.28CR	77,850.00CR
Current State	38,159.09CR	.00	38,159.09CR	.00	.00	62,528.36	56,100.00
Deferred Federal & State	60,835.00	5,350.00CR	60,835.00	.00	5,350.00CR	2,275,768.70	2,073,750.00
Investment Tax Credit-Net	.00	2,775.00CR	.00	.00	2,775.00CR	30,525.00CR	35,591.63CR
Total Income Taxes	180,584.83CR	160,575.00CR	180,584.83CR	125,600.00CR	160,575.00CR	1,888,922.78	2,016,408.37
TOTAL OPERATING EXPENSES	1,813,449.40	2,275,533.51	1,813,449.40	2,690,700.00	2,275,533.51	59,723,748.86	54,735,326.98

DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

July 01, 2009 - July 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	54,917.61CR	112,475.40CR	54,917.61CR	188,500.00CR	112,475.40CR	7,660,917.86CR	7,892,698.95CR
Income Before Interest Charges	54,917.61CR	112,475.40CR	54,917.61CR	188,500.00CR	112,475.40CR	7,660,917.86CR	7,892,698.95CR
INTEREST CHARGES							
Interest On Long-Term Debt	301,745.84	305,881.04	301,745.84	303,200.00	305,881.04	3,644,107.80	3,676,736.15
Interest On Short-Term Debt	19.01CR	25,466.47	19.01CR	55,300.00	25,466.47	210,438.24	440,923.87
Other Interest	2,342.75	2,457.19	2,342.75	3,100.00	2,457.19	33,112.79	32,858.58
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	336,341.46	366,076.58	336,341.46	393,900.00	366,076.58	4,274,921.39	4,537,784.16
NET INCOME	281,423.85	253,601.18	281,423.85	205,400.00	253,601.18	3,385,996.47CR	3,354,914.79CR

DELTA NATURAL GAS CO., INC SUBSIDIARIES

Income Statement-Delta Natural FERC REG

August 01, 2009 - August 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	741,906.71CR	949,115.51CR	741,906.71CR	830,200.00CR	949,115.51CR	33,584,829.56CR	31,054,408.43CR
Small Commercial	208,514.07CR	287,618.09CR	208,514.07CR	244,200.00CR	287,618.09CR	10,097,958.41CR	9,153,417.63CR
Other Commercial	339,783.82CR	559,177.52CR	339,783.82CR	1,219,700.00CR	559,177.52CR	13,500,210.93CR	12,289,467.67CR
Industrial	24,816.82CR	41,078.70CR	24,816.82CR	.00	41,078.70CR	1,343,645.14CR	1,308,562.34CR
Unmetered Gas Light	357.48CR	801.25CR	357.48CR	700.00CR	801.25CR	6,842.57CR	8,315.23CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	16.04CR	.00	16.04CR	.00	.00	624.28CR	.00
Total General Service Ra	1,315,394.94CR	1,837,791.07CR	1,315,394.94CR	2,294,800.00CR	1,837,791.07CR	58,282,688.43CR	53,989,382.73CR
Interuptible Rate Billed							
Commercial	.00	.00	.00	.00	.00	36,643.62CR	34,807.00CR
Industrial	9,577.87CR	18,187.45CR	9,577.87CR	11,300.00CR	18,187.45CR	375,260.31CR	409,776.11CR
Total Interruptible Rate	9,577.87CR	18,187.45CR	9,577.87CR	11,300.00CR	18,187.45CR	411,903.93CR	444,583.11CR
Total Gas Revenue	1,324,972.81CR	1,855,978.52CR	1,324,972.81CR	2,306,100.00CR	1,855,978.52CR	58,694,592.36CR	54,433,965.84CR
Miscellaneous Operating Revenue	16,635.00CR	19,075.00CR	16,635.00CR	27,300.00CR	19,075.00CR	326,745.00CR	315,336.00CR
Off System Transportation Reven	248,740.74CR	328,997.40CR	248,740.74CR	271,500.00CR	328,997.40CR	3,640,443.76CR	3,933,853.31CR
On System Transportation Revenu	291,751.96CR	286,518.04CR	291,751.96CR	274,300.00CR	286,518.04CR	4,114,417.15CR	4,472,207.43CR
TOTAL OPERATING REVENUE	1,882,100.51CR	2,490,568.96CR	1,882,100.51CR	2,879,200.00CR	2,490,568.96CR	66,776,198.27CR	63,155,362.58CR
OPERATING EXPENSES							
Purchased Gas	458,803.97	963,856.72	458,803.97	1,244,500.00	963,856.72	38,186,876.01	33,985,330.14
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	458,803.97	963,856.72	458,803.97	1,244,500.00	963,856.72	38,186,876.01	33,985,330.14
Operation Expense							
Labor	542,374.43	536,227.69	542,374.43	555,500.00	536,227.69	6,895,452.85	7,109,318.53
Transportation	75,646.00	78,389.26	75,646.00	78,900.00	78,389.26	847,176.75	931,954.40

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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

August 01, 2009 - August 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	48,729.13	43,564.96	48,729.13	43,000.00	43,564.96	498,954.47	816,724.04
Customer Billing	43,082.01	33,331.63	43,082.01	27,400.00	33,331.63	338,069.86	290,768.34
Uncollectible Accounts	.00	.00	.00	4,500.00	.00	361,587.94	599,344.83
Administrative	44,494.67	47,962.86	44,494.67	49,300.00	47,962.86	566,257.96	566,786.25
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Outside Services	132,921.83	59,280.12	132,921.83	66,400.00	59,280.12	994,344.44	816,538.68
Insurance	75,965.44	65,909.23	75,965.44	69,800.00	65,909.23	820,837.35	790,896.71
Employee Benefits	259,381.66	237,362.99	259,381.66	292,700.00	237,362.99	2,882,112.42	2,515,173.99
General Administration	56,298.74	43,660.67	56,298.74	39,300.00	43,660.67	748,565.70	773,600.45
Expenses Transferred	260,962.45CR	248,895.35CR	260,962.45CR	237,600.00CR	248,895.35CR	3,259,714.84CR	3,527,855.27CR
Other	19,185.35	34,790.52	19,185.35	61,100.00	34,790.52	1,279,366.13	450,137.16
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Total Operation Expense	1,037,116.81	931,584.58	1,037,116.81	1,050,300.00	931,584.58	12,973,011.03	12,133,388.11
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Maintenance Expense							
Labor	13,104.71	9,777.24	13,104.71	.00	9,777.24	106,890.86	120,520.42
Transportation	5,178.45	3,751.24	5,178.45	.00	3,751.24	41,355.56	48,856.89
Mains	5,560.39	10,466.53	5,560.39	6,000.00	10,466.53	74,765.19	222,721.20
Meter & Regulators	976.23	3,531.24	976.23	4,000.00	3,531.24	47,427.05	49,300.19
Other	30,857.03	34,844.15	30,857.03	42,600.00	34,844.15	389,387.35	563,297.12
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Total Maintenance Expens	55,676.81	62,370.40	55,676.81	52,600.00	62,370.40	659,826.01	1,004,695.82
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Depreciation Expense	318,400.57	306,943.48	318,400.57	315,000.00	306,943.48	3,760,794.08	3,849,820.95
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Taxes Other Than Income Taxes							
Property Taxes	109,919.25	105,662.00	109,919.25	104,900.00	105,662.00	1,291,083.48	1,199,862.78
Payroll Taxes	35,821.51	32,077.54	35,821.51	49,000.00	32,077.54	576,479.67	582,457.38
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Total Other Taxes	145,740.76	137,739.54	145,740.76	153,900.00	137,739.54	1,867,563.15	1,782,320.16
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Income Taxes							
Current Federal	110,694.83CR	99,850.00CR	110,694.83CR	125,600.00CR	99,850.00CR	429,694.11CR	116,900.00
Current State	20,781.25CR	.00	20,781.25CR	.00	.00	41,747.11	56,100.00
Deferred Federal & State	50,883.28CR	5,350.00CR	50,883.28CR	.00	5,350.00CR	2,230,235.42	2,073,500.00
Investment Tax Credit-Net	.00	2,775.00CR	.00	.00	2,775.00CR	27,750.00CR	35,383.30CR
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Total Income Taxes	182,359.36CR	107,975.00CR	182,359.36CR	125,600.00CR	107,975.00CR	1,814,538.42	2,211,116.70
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TOTAL OPERATING EXPENSES	1,833,379.56	2,294,519.72	1,833,379.56	2,690,700.00	2,294,519.72	59,262,608.70	54,966,671.88
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DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement - Delta

August 01, 2009 - August 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	48,720.95CR	196,049.24CR	48,720.95CR	188,500.00CR	196,049.24CR	7,513,589.57CR	8,188,690.70CR
Income Before Interest Charges	48,720.95CR	196,049.24CR	48,720.95CR	188,500.00CR	196,049.24CR	7,513,589.57CR	8,188,690.70CR
INTEREST CHARGES							
Interest On Long-Term Debt	301,429.17	305,700.00	301,429.17	303,200.00	305,700.00	3,639,836.97	3,675,336.15
Interest On Short-Term Debt	1,027.15	37,262.57	1,027.15	55,300.00	37,262.57	174,202.82	419,243.95
Other Interest	2,456.98	2,380.97	2,456.98	3,100.00	2,380.97	33,188.80	32,792.16
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	337,185.18	377,615.42	337,185.18	393,900.00	377,615.42	4,234,491.15	4,514,637.82
NET INCOME	288,464.23	181,566.18	288,464.23	205,400.00	181,566.18	3,279,098.42CR	3,674,052.88CR

DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement-Delta Natural FERC REG

September 01, 2009 - September 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	832,554.19CR	1,012,714.47CR	832,554.19CR	830,200.00CR	1,012,714.47CR	33,404,669.28CR	31,337,761.65CR
Small Commercial	231,016.64CR	281,659.09CR	231,016.64CR	244,200.00CR	281,659.09CR	10,047,315.96CR	9,198,789.20CR
Other Commercial	434,048.60CR	584,017.73CR	434,048.60CR	1,219,700.00CR	584,017.73CR	13,350,241.80CR	12,423,796.87CR
Industrial	30,856.78CR	40,449.45CR	30,856.78CR	.00	40,449.45CR	1,334,052.47CR	1,317,072.50CR
Unmetered Gas Light	357.48CR	833.30CR	357.48CR	700.00CR	833.30CR	6,366.75CR	8,416.23CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	12.62CR	.00	12.62CR	.00	.00	636.90CR	.00
Total General Service Ra	1,528,846.31CR	1,919,674.04CR	1,528,846.31CR	2,294,800.00CR	1,919,674.04CR	57,891,860.70CR	54,461,047.88CR
Interuptible Rate Billed							
Commercial	.00	.00	.00	.00	.00	36,643.62CR	34,807.00CR
Industrial	10,130.52CR	14,660.06CR	10,130.52CR	11,300.00CR	14,660.06CR	370,730.77CR	411,379.67CR
Total Interruptible Rate	10,130.52CR	14,660.06CR	10,130.52CR	11,300.00CR	14,660.06CR	407,374.39CR	446,186.67CR
Total Gas Revenue	1,538,976.83CR	1,934,334.10CR	1,538,976.83CR	2,306,100.00CR	1,934,334.10CR	58,299,235.09CR	54,907,234.55CR
Miscellaneous Operating Revenue	9,850.00CR	12,820.00CR	9,850.00CR	27,300.00CR	12,820.00CR	323,775.00CR	319,488.00CR
Off System Transportation Reven	219,009.42CR	289,548.95CR	219,009.42CR	271,500.00CR	289,548.95CR	3,569,904.23CR	3,971,125.04CR
On System Transportation Revenu	300,542.74CR	295,822.26CR	300,542.74CR	274,300.00CR	295,822.26CR	4,119,137.63CR	4,485,980.69CR
TOTAL OPERATING REVENUE	2,068,378.99CR	2,532,525.31CR	2,068,378.99CR	2,879,200.00CR	2,532,525.31CR	66,312,051.95CR	63,683,828.28CR
OPERATING EXPENSES							
Purchased Gas	634,638.58	972,722.26	634,638.58	1,244,500.00	972,722.26	37,848,792.33	34,217,530.54
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	634,638.58	972,722.26	634,638.58	1,244,500.00	972,722.26	37,848,792.33	34,217,530.54
Operation Expense							
Labor	551,338.10	546,400.36	551,338.10	555,500.00	546,400.36	6,900,390.59	7,128,053.02
Transportation	57,123.95	74,121.01	57,123.95	78,900.00	74,121.01	830,179.69	948,313.81

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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement - Delta

September 01, 2009 - September 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	40,155.74	46,875.74	40,155.74	43,000.00	46,875.74	492,234.47	803,443.25
Customer Billing	20,797.85	21,730.34	20,797.85	27,400.00	21,730.34	337,137.37	290,243.90
Uncollectible Accounts	.00	.00	.00	4,500.00	.00	361,587.94	644,344.83
Administrative	47,009.89	50,047.30	47,009.89	49,300.00	50,047.30	563,220.55	572,763.43
Outside Services	135,132.22	84,420.54	135,132.22	66,400.00	84,420.54	1,045,056.12	819,217.01
Insurance	69,469.74	57,929.29	69,469.74	69,800.00	57,929.29	832,377.80	786,580.79
Employee Benefits	269,310.66	155,278.57	269,310.66	292,700.00	155,278.57	2,996,144.51	2,444,205.56
General Administration	34,641.40	54,742.78	34,641.40	39,300.00	54,742.78	728,464.32	752,077.64
Expenses Transferred	242,868.81CR	251,234.57CR	242,868.81CR	237,600.00CR	251,234.57CR	3,251,349.08CR	3,541,254.34CR
Other	65,981.39	35,017.68	65,981.39	61,100.00	35,017.68	1,310,329.84	439,588.22
Total Operation Expense	1,048,092.13	875,329.04	1,048,092.13	1,050,300.00	875,329.04	13,145,774.12	12,087,577.12
Maintenance Expense							
Labor	20,693.20	11,535.92	20,693.20	.00	11,535.92	116,048.14	119,786.03
Transportation	8,127.35	4,503.04	8,127.35	.00	4,503.04	44,979.87	49,575.53
Mains	9,647.19	11,892.73	9,647.19	6,000.00	11,892.73	72,519.65	215,478.06
Meter & Regulators	2,410.70	7,147.29	2,410.70	4,000.00	7,147.29	42,690.46	50,620.78
Other	23,194.08	28,713.89	23,194.08	42,600.00	28,713.89	383,867.54	616,586.02
Total Maintenance Expens	64,072.52	63,792.87	64,072.52	52,600.00	63,792.87	660,105.66	1,052,046.42
Depreciation Expense	318,172.62	307,470.09	318,172.62	315,000.00	307,470.09	3,771,496.61	3,744,194.99
Taxes Other Than Income Taxes							
Property Taxes	109,897.00	105,387.00	109,897.00	104,900.00	105,387.00	1,295,593.48	1,201,217.78
Payroll Taxes	42,099.88	41,837.39	42,099.88	49,000.00	41,837.39	576,742.16	582,627.73
Total Other Taxes	151,996.88	147,224.39	151,996.88	153,900.00	147,224.39	1,872,335.64	1,783,845.51
Income Taxes							
Current Federal	3,336,830.22CR	87,009.00CR	3,336,830.22CR	125,600.00CR	87,009.00CR	3,679,515.33CR	254,625.00
Current State	613,952.75CR	.00	613,952.75CR	.00	.00	572,205.64CR	56,100.00
Deferred Federal & State	3,755,024.02	5,350.00CR	3,755,024.02	.00	5,350.00CR	5,990,609.44	2,074,900.00
Investment Tax Credit-Net	7,650.00CR	2,775.00CR	7,650.00CR	.00	2,775.00CR	32,625.00CR	35,174.97CR
Total Income Taxes	203,408.95CR	95,134.00CR	203,408.95CR	125,600.00CR	95,134.00CR	1,706,263.47	2,350,450.03
TOTAL OPERATING EXPENSES	2,013,563.78	2,271,404.65	2,013,563.78	2,690,700.00	2,271,404.65	59,004,767.83	55,235,644.61

DELTA NATURAL GAS CO., INC. ;UBSIDIARIES

Income Statement - Delta

September 01, 2009 - September 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	54,815.21CR	261,120.66CR	54,815.21CR	188,500.00CR	261,120.66CR	7,307,284.12CR	8,448,183.67CR
Income Before Interest Charges	54,815.21CR	261,120.66CR	54,815.21CR	188,500.00CR	261,120.66CR	7,307,284.12CR	8,448,183.67CR
INTEREST CHARGES							
Interest On Long-Term Debt	300,964.99	305,429.17	300,964.99	303,200.00	305,429.17	3,635,372.79	3,673,827.09
Interest On Short-Term Debt	5,336.33	37,059.07	5,336.33	55,300.00	37,059.07	142,480.08	393,084.31
Other Interest	2,460.05	2,514.75	2,460.05	3,100.00	2,514.75	33,134.10	32,917.07
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	341,033.25	377,274.87	341,033.25	393,900.00	377,274.87	4,198,249.53	4,487,094.03
NET INCOME	286,218.04	116,154.21	286,218.04	205,400.00	116,154.21	3,109,034.59CR	3,961,089.64CR

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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement-Delta Natural FERC REG

October 01, 2009 - October 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	1,409,321.45CR	1,953,238.72CR	1,409,321.45CR	830,200.00CR	1,953,238.72CR	32,860,752.01CR	32,061,204.40CR
Small Commercial	351,954.83CR	543,925.24CR	351,954.83CR	244,200.00CR	543,925.24CR	9,855,345.55CR	9,426,619.44CR
Other Commercial	514,875.44CR	928,296.26CR	514,875.44CR	1,219,700.00CR	928,296.26CR	12,936,820.98CR	12,828,022.49CR
Industrial	31,437.66CR	64,163.97CR	31,437.66CR	.00	64,163.97CR	1,301,326.16CR	1,341,387.64CR
Unmetered Gas Light	357.48CR	769.20CR	357.48CR	700.00CR	769.20CR	5,955.03CR	8,453.13CR
Residential WNA	.00	.00	.00	.00	.00	191,282.46	134,604.03CR
Small Non-Residential WNA	.00	.00	.00	.00	.00	60,140.00	40,607.40CR
Weather Normalization Revenu	.00	.00	.00	.00	.00	251,422.46	175,211.43CR
Demand-Side Revenue	17.03CR	1,049.00CR	17.03CR	.00	1,049.00CR	395.07	1,049.00CR
Total General Service Ra	2,307,963.89CR	3,491,442.39CR	2,307,963.89CR	2,294,800.00CR	3,491,442.39CR	56,708,382.20CR	55,841,947.53CR
Interuptible Rate Billed							
Commercial	1,321.00CR	4,187.00CR	1,321.00CR	.00	4,187.00CR	33,777.62CR	37,250.00CR
Industrial	10,172.95CR	18,627.90CR	10,172.95CR	11,300.00CR	18,627.90CR	362,275.82CR	412,797.83CR
Total Interruptible Rate	11,493.95CR	22,814.90CR	11,493.95CR	11,300.00CR	22,814.90CR	396,053.44CR	450,047.83CR
Total Gas Revenue	2,319,457.84CR	3,514,257.29CR	2,319,457.84CR	2,306,100.00CR	3,514,257.29CR	57,104,435.64CR	56,291,995.36CR
Miscellaneous Operating Revenue	20,820.00CR	21,010.00CR	20,820.00CR	27,300.00CR	21,010.00CR	323,585.00CR	329,062.00CR
Off System Transportation Reven	240,339.15CR	343,726.66CR	240,339.15CR	271,500.00CR	343,726.66CR	3,466,516.72CR	4,028,487.78CR
On System Transportation Revenu	385,248.97CR	354,825.44CR	385,248.97CR	274,300.00CR	354,825.44CR	4,149,561.16CR	4,504,280.85CR
TOTAL OPERATING REVENUE	2,965,865.96CR	4,233,819.39CR	2,965,865.96CR	2,879,200.00CR	4,233,819.39CR	65,044,098.52CR	65,153,825.99CR
OPERATING EXPENSES							
Purchased Gas	1,036,119.00	2,164,044.03	1,036,119.00	1,244,500.00	2,164,044.03	36,720,867.30	35,269,799.30
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	1,036,119.00	2,164,044.03	1,036,119.00	1,244,500.00	2,164,044.03	36,720,867.30	35,269,799.30
Operation Expense							
Labor	550,230.85	541,886.98	550,230.85	555,500.00	541,886.98	6,908,734.46	7,146,466.46
Transportation	78,287.80	81,665.65	78,287.80	78,900.00	81,665.65	826,801.84	963,098.86

DELTA NATURAL GAS CO., INC. SUBSIDIARIES

Income Statement - Delta

October 01, 2009 - October 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	39,758.19	43,824.50	39,758.19	43,000.00	43,824.50	488,168.16	808,982.86
Customer Billing	20,404.60	23,022.58	20,404.60	27,400.00	23,022.58	334,519.39	286,986.74
Uncollectible Accounts	.00	.00	.00	4,500.00	.00	361,587.94	593,644.83
Administrative	44,666.85	50,400.34	44,666.85	49,300.00	50,400.34	557,487.06	576,880.24
Outside Services	74,576.89	67,606.71	74,576.89	66,400.00	67,606.71	1,052,026.30	811,249.24
Insurance	69,728.54	64,782.66	69,728.54	69,800.00	64,782.66	837,323.68	783,581.14
Employee Benefits	180,294.25	195,589.73	180,294.25	292,700.00	195,589.73	2,980,849.03	2,449,051.58
General Administration	86,262.09	68,668.08	86,262.09	39,300.00	68,668.08	746,058.33	775,947.76
Expenses Transferred	242,004.26CR	248,864.29CR	242,004.26CR	237,600.00CR	248,864.29CR	3,244,489.05CR	3,545,147.37CR
Other	39,790.72	40,925.93	39,790.72	61,100.00	40,925.93	1,309,194.63	432,804.72
Total Operation Expense	941,996.52	929,508.87	941,996.52	1,050,300.00	929,508.87	13,158,261.77	12,083,547.06
Maintenance Expense							
Labor	8,078.21	11,473.18	8,078.21	.00	11,473.18	112,653.17	118,564.52
Transportation	3,470.41	4,938.11	3,470.41	.00	4,938.11	43,512.17	50,672.44
Mains	3,706.10	7,777.84	3,706.10	6,000.00	7,777.84	68,447.91	168,444.86
Meter & Regulators	3,017.59	1,811.22	3,017.59	4,000.00	1,811.22	43,896.83	51,201.03
Other	40,959.84	39,459.80	40,959.84	42,600.00	39,459.80	385,367.58	584,575.28
Total Maintenance Expens	59,232.15	65,460.15	59,232.15	52,600.00	65,460.15	653,877.66	973,458.13
Depreciation Expense	319,639.02	309,678.68	319,639.02	315,000.00	309,678.68	3,781,456.95	3,641,167.66
Taxes Other Than Income Taxes							
Property Taxes	111,897.00	105,407.00	111,897.00	104,900.00	105,407.00	1,302,083.48	1,202,572.78
Payroll Taxes	42,166.84	42,391.65	42,166.84	49,000.00	42,391.65	576,517.35	582,806.03
Total Other Taxes	154,063.84	147,798.65	154,063.84	153,900.00	147,798.65	1,878,600.83	1,785,378.81
Income Taxes							
Current Federal	94,291.91	83,150.00	94,291.91	125,600.00CR	83,150.00	3,668,373.42CR	475,325.00
Current State	17,701.86	.00	17,701.86	.00	.00	554,503.78CR	56,100.00
Deferred Federal & State	75,547.65CR	5,350.00CR	75,547.65CR	.00	5,350.00CR	5,920,411.79	2,074,900.00
Investment Tax Credit-Net	2,550.00CR	2,775.00CR	2,550.00CR	.00	2,775.00CR	32,400.00CR	34,966.64CR
Total Income Taxes	33,896.12	75,025.00	33,896.12	125,600.00CR	75,025.00	1,665,134.59	2,571,358.36
TOTAL OPERATING EXPENSES	2,544,946.65	3,691,515.38	2,544,946.65	2,690,700.00	3,691,515.38	57,858,199.10	56,324,709.32

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DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement - Delta

October 01, 2009 - October 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	420,919.31CR	542,304.01CR	420,919.31CR	188,500.00CR	542,304.01CR	7,185,899.42CR	8,829,116.67CR
Income Before Interest Charges	420,919.31CR	542,304.01CR	420,919.31CR	188,500.00CR	542,304.01CR	7,185,899.42CR	8,829,116.67CR
INTEREST CHARGES							
Interest On Long-Term Debt	300,955.83	305,035.00	300,955.83	303,200.00	305,035.00	3,631,293.62	3,672,152.09
Interest On Short-Term Debt	9,914.64	81,525.07	9,914.64	55,300.00	81,525.07	70,869.65	414,921.23
Other Interest	2,418.85	2,339.15	2,418.85	3,100.00	2,339.15	33,213.80	32,871.57
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	345,561.20	421,171.10	345,561.20	393,900.00	421,171.10	4,122,639.63	4,507,210.45
NET INCOME	75,358.11CR	121,132.91CR	75,358.11CR	205,400.00	121,132.91CR	3,063,259.79CR	4,321,906.22CR

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DELTA NATURAL GAS CO., INC. UBSIDIARIES

Income Statement-Delta Natural FERC REG

November 01, 2009 - November 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	2,142,800.08CR	4,232,274.61CR	2,142,800.08CR	830,200.00CR	4,232,274.61CR	30,771,277.48CR	33,114,616.36CR
Small Commercial	558,441.90CR	1,226,392.19CR	558,441.90CR	244,200.00CR	1,226,392.19CR	9,187,395.26CR	9,797,167.35CR
Other Commercial	758,316.67CR	1,719,490.22CR	758,316.67CR	1,219,700.00CR	1,719,490.22CR	11,975,647.43CR	13,407,575.23CR
Industrial	65,760.95CR	168,445.36CR	65,760.95CR	.00	168,445.36CR	1,198,641.75CR	1,399,419.20CR
Unmetered Gas Light	308.37CR	622.32CR	308.37CR	700.00CR	622.32CR	5,641.08CR	8,420.12CR
Residential WNA	64,985.00CR	161,568.00CR	64,985.00CR	.00	161,568.00CR	287,865.46	296,171.81CR
Small Non-Residential WNA	15,431.00CR	48,030.00CR	15,431.00CR	.00	48,030.00CR	92,739.00	88,637.40CR
Weather Normalization Revenu	80,416.00CR	209,598.00CR	80,416.00CR	.00	209,598.00CR	380,604.46	384,809.21CR
Demand-Side Revenue	58.52CR	.00	58.52CR	.00	.00	336.55	1,049.00CR
Total General Service Ra	3,606,102.49CR	7,556,822.70CR	3,606,102.49CR	2,294,800.00CR	7,556,822.70CR	52,757,661.99CR	58,113,056.47CR
Interuptible Rate Billed							
Commercial	2,135.17CR	6,064.71CR	2,135.17CR	.00	6,064.71CR	29,848.08CR	38,003.33CR
Industrial	12,876.20CR	36,530.10CR	12,876.20CR	11,300.00CR	36,530.10CR	338,621.92CR	416,636.29CR
Total Interruptible Rate	15,011.37CR	42,594.81CR	15,011.37CR	11,300.00CR	42,594.81CR	368,470.00CR	454,639.62CR
Total Gas Revenue	3,621,113.86CR	7,599,417.51CR	3,621,113.86CR	2,306,100.00CR	7,599,417.51CR	53,126,131.99CR	58,567,696.09CR
Miscellaneous Operating Revenue	34,445.00CR	49,770.00CR	34,445.00CR	27,300.00CR	49,770.00CR	308,260.00CR	340,323.00CR
Off System Transportation Reven	266,675.49CR	311,023.75CR	266,675.49CR	271,500.00CR	311,023.75CR	3,422,168.46CR	4,072,944.85CR
On System Transportation Revenu	379,508.26CR	422,632.91CR	379,508.26CR	274,300.00CR	422,632.91CR	4,106,436.51CR	4,496,358.82CR
TOTAL OPERATING REVENUE	4,301,742.61CR	8,382,844.17CR	4,301,742.61CR	2,879,200.00CR	8,382,844.17CR	60,962,996.96CR	67,477,322.76CR
OPERATING EXPENSES							
Purchased Gas	1,772,492.52	5,195,121.75	1,772,492.52	1,244,500.00	5,195,121.75	33,298,238.07	37,262,645.39
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	1,772,492.52	5,195,121.75	1,772,492.52	1,244,500.00	5,195,121.75	33,298,238.07	37,262,645.39
Operation Expense							
Labor	551,022.99	558,123.21	551,022.99	555,500.00	558,123.21	6,901,634.24	7,175,812.29
Transportation	62,235.55	64,888.04	62,235.55	78,900.00	64,888.04	824,149.35	971,378.10

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DELTA NATURAL GAS CO., INC. BSIDIARIES

Income Statement - Delta

November 01, 2009 - November 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	75,195.79	37,345.83	75,195.79	43,000.00	37,345.83	526,018.12	797,328.37
Customer Billing	21,968.17	26,100.43	21,968.17	27,400.00	26,100.43	330,387.13	306,434.84
Uncollectible Accounts	.00	.00	.00	4,500.00	.00	361,587.94	542,944.83
Administrative	42,069.50	44,277.10	42,069.50	49,300.00	44,277.10	555,279.46	573,133.66
Outside Services	75,619.44	94,804.01	75,619.44	66,400.00	94,804.01	1,032,841.73	852,161.09
Insurance	69,530.04	64,684.16	69,530.04	69,800.00	64,684.16	842,169.56	779,885.27
Employee Benefits	263,199.50	224,514.94	263,199.50	292,700.00	224,514.94	3,019,533.59	2,519,493.47
General Administration	49,302.81	52,720.28	49,302.81	39,300.00	52,720.28	742,640.86	779,667.72
Expenses Transferred	257,293.59CR	227,378.32CR	257,293.59CR	237,600.00CR	227,378.32CR	3,274,404.32CR	3,530,760.78CR
Other	47,775.19	35,672.12	47,775.19	61,100.00	35,672.12	1,321,297.70	416,265.11
Total Operation Expense	1,000,625.39	975,751.80	1,000,625.39	1,050,300.00	975,751.80	13,183,135.36	12,183,743.97
Maintenance Expense							
Labor	4,559.61	9,400.23	4,559.61	.00	9,400.23	107,812.55	118,055.44
Transportation	1,797.36	3,202.79	1,797.36	.00	3,202.79	42,106.74	50,457.23
Mains	7,163.62	3,587.39	7,163.62	6,000.00	3,587.39	72,024.14	138,034.98
Meter & Regulators	1,442.45	3,532.47	1,442.45	4,000.00	3,532.47	41,806.81	53,670.43
Other	23,856.04	22,761.61	23,856.04	42,600.00	22,761.61	386,462.01	585,874.83
Total Maintenance Expens	38,819.08	42,484.49	38,819.08	52,600.00	42,484.49	650,212.25	946,092.91
Depreciation Expense	316,048.85	310,824.08	316,048.85	315,000.00	310,824.08	3,786,681.72	3,651,861.50
Taxes Other Than Income Taxes							
Property Taxes	109,897.00	105,387.00	109,897.00	104,900.00	105,387.00	1,306,593.48	1,203,927.78
Payroll Taxes	41,602.61	41,344.93	41,602.61	49,000.00	41,344.93	576,775.03	583,433.63
Total Other Taxes	151,499.61	146,731.93	151,499.61	153,900.00	146,731.93	1,883,368.51	1,787,361.41
Income Taxes							
Current Federal	201,741.98	517,850.00	201,741.98	125,600.00CR	517,850.00	3,984,481.44CR	582,025.00
Current State	37,873.96	.00	37,873.96	.00	.00	516,629.82CR	56,100.00
Deferred Federal & State	13,194.75	5,350.00CR	13,194.75	.00	5,350.00CR	5,938,956.54	2,074,900.00
Investment Tax Credit-Net	2,550.00CR	2,775.00CR	2,550.00CR	.00	2,775.00CR	32,175.00CR	34,758.31CR
Total Income Taxes	250,260.69	509,725.00	250,260.69	125,600.00CR	509,725.00	1,405,670.28	2,678,266.69
TOTAL OPERATING EXPENSES	3,529,746.14	7,180,639.05	3,529,746.14	2,690,700.00	7,180,639.05	54,207,306.19	58,509,971.87

DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement - Delta

November 01, 2009 - November 30, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	771,996.47CR	1,202,205.12CR	771,996.47CR	188,500.00CR	1,202,205.12CR	6,755,690.77CR	8,967,350.89CR
Income Before Interest Charges	771,996.47CR	1,202,205.12CR	771,996.47CR	188,500.00CR	1,202,205.12CR	6,755,690.77CR	8,967,350.89CR
INTEREST CHARGES							
Interest On Long-Term Debt	300,600.00	304,700.00	300,600.00	303,200.00	304,700.00	3,627,193.62	3,670,252.09
Interest On Short-Term Debt	7,796.56	33,551.20	7,796.56	55,300.00	33,551.20	45,115.01	381,237.27
Other Interest	2,756.97	2,704.26	2,756.97	3,100.00	2,704.26	33,266.51	33,006.44
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	343,425.41	373,227.34	343,425.41	393,900.00	373,227.34	4,092,837.70	4,471,761.36
NET INCOME	428,571.06CR	828,977.78CR	428,571.06CR	205,400.00	828,977.78CR	2,662,853.07CR	4,495,589.53CR

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DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement-Delta Natural FERC REG

December 01, 2009 - December 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
01							
OPERATING REVENUES							
General Service Rate Billed							
Residential	3,905,404.00CR	5,877,721.81CR	3,905,404.00CR	830,200.00CR	5,877,721.81CR	28,798,959.67CR	34,558,275.42CR
Small Commercial	1,183,140.87CR	1,846,039.75CR	1,183,140.87CR	244,200.00CR	1,846,039.75CR	8,524,496.38CR	10,323,330.81CR
Other Commercial	1,346,716.53CR	2,142,886.17CR	1,346,716.53CR	1,219,700.00CR	2,142,886.17CR	11,179,477.79CR	13,944,654.21CR
Industrial	150,024.99CR	235,654.62CR	150,024.99CR	.00	235,654.62CR	1,113,012.12CR	1,439,407.41CR
Unmetered Gas Light	308.37CR	700.11CR	308.37CR	700.00CR	700.11CR	5,249.34CR	8,486.33CR
Residential WNA	46,602.34	353,927.42	46,602.34	.00	353,927.42	19,459.62CR	219,733.36
Small Non-Residential WNA	16,272.14	110,143.03	16,272.14	.00	110,143.03	1,131.89CR	71,440.86
Weather Normalization Revenu	62,874.48	464,070.45	62,874.48	.00	464,070.45	20,591.51CR	291,174.22
Demand-Side Revenue	86.93CR	.00	86.93CR	.00	.00	249.62	1,049.00CR
Total General Service Ra	6,522,807.21CR	9,638,932.01CR	6,522,807.21CR	2,294,800.00CR	9,638,932.01CR	49,641,537.19CR	59,984,028.96CR
Interuptible Rate Billed							
Commercial	3,461.22CR	6,058.47CR	3,461.22CR	.00	6,058.47CR	27,250.83CR	38,711.48CR
Industrial	39,569.35CR	63,380.52CR	39,569.35CR	11,300.00CR	63,380.52CR	314,810.75CR	424,916.25CR
Total Interruptible Rate	43,030.57CR	69,438.99CR	43,030.57CR	11,300.00CR	69,438.99CR	342,061.58CR	463,627.73CR
Total Gas Revenue	6,565,837.78CR	9,708,371.00CR	6,565,837.78CR	2,306,100.00CR	9,708,371.00CR	49,983,598.77CR	60,447,656.69CR
Miscellaneous Operating Revenue	22,375.00CR	28,055.00CR	22,375.00CR	27,300.00CR	28,055.00CR	302,580.00CR	346,345.00CR
Off System Transportation Reven	366,110.01CR	372,374.82CR	366,110.01CR	271,500.00CR	372,374.82CR	3,415,903.65CR	4,059,755.35CR
On System Transportation Revenu	451,307.93CR	422,800.15CR	451,307.93CR	274,300.00CR	422,800.15CR	4,134,944.29CR	4,469,954.09CR
TOTAL OPERATING REVENUE	7,405,630.72CR	10,531,600.97CR	7,405,630.72CR	2,879,200.00CR	10,531,600.97CR	57,837,026.71CR	69,323,711.13CR
OPERATING EXPENSES							
Purchased Gas	3,721,333.36	7,193,017.73	3,721,333.36	1,244,500.00	7,193,017.73	29,826,553.70	39,616,717.01
Recovery of Canada Mountain	.00	.00	.00	.00	.00	.00	.00
Purchased Gas, net	3,721,333.36	7,193,017.73	3,721,333.36	1,244,500.00	7,193,017.73	29,826,553.70	39,616,717.01
Operation Expense							
Labor	470,013.18	463,780.97	470,013.18	555,500.00	463,780.97	6,907,866.45	7,206,578.98
Transportation	84,625.50	76,223.97	84,625.50	78,900.00	76,223.97	832,550.88	951,310.47

DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement - Delta

December 01, 2009 - December 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
General Operations	89,480.00	36,036.89	89,480.00	43,000.00	36,036.89	579,461.23	781,776.73
Customer Billing	33,600.80	24,926.70	33,600.80	27,400.00	24,926.70	339,061.23	292,970.14
Uncollectible Accounts	116,000.00	663,000.00	116,000.00	4,500.00	663,000.00	185,412.06CR	1,085,944.83
Administrative	43,639.09	49,788.98	43,639.09	49,300.00	49,788.98	549,129.57	581,151.51
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Outside Services	94,618.22	42,299.59	94,618.22	66,400.00	42,299.59	1,085,160.36	833,081.78
Insurance	69,628.54	65,482.66	69,628.54	69,800.00	65,482.66	846,315.44	777,860.85
Employee Benefits	331,596.32	361,979.23	331,596.32	292,700.00	361,979.23	2,989,150.68	2,598,896.50
General Administration	93,376.30	85,694.67	93,376.30	39,300.00	85,694.67	750,322.49	790,312.72
Expenses Transferred	261,023.10CR	221,351.90CR	261,023.10CR	237,600.00CR	221,351.90CR	3,314,075.52CR	3,510,773.32CR
Other	20,495.86	41,596.91	20,495.86	61,100.00	41,596.91	1,300,196.65	429,010.45
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Total Operation Expense	1,186,050.71	1,689,458.67	1,186,050.71	1,050,300.00	1,689,458.67	12,679,727.40	12,818,121.64
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Maintenance Expense							
Labor	7,427.52	3,335.05	7,427.52	.00	3,335.05	111,905.02	115,109.44
Transportation	3,005.55	2,993.14	3,005.55	.00	2,993.14	42,119.15	49,314.57
Mains	8,019.77	3,593.86	8,019.77	6,000.00	3,593.86	76,450.05	137,917.30
Meter & Regulators	315.25	3,065.68	315.25	4,000.00	3,065.68	39,056.38	52,067.19
Other	21,921.57	32,860.16	21,921.57	42,600.00	32,860.16	375,523.42	591,421.50
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Total Maintenance Expens	40,689.66	45,847.89	40,689.66	52,600.00	45,847.89	645,054.02	945,830.00
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Depreciation Expense	317,133.65	311,557.81	317,133.65	315,000.00	311,557.81	3,792,257.56	3,662,475.11
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Taxes Other Than Income Taxes							
Property Taxes	105,753.00	84,497.23	105,753.00	104,900.00	84,497.23	1,327,849.25	1,204,138.01
Payroll Taxes	43,486.69	43,231.54	43,486.69	49,000.00	43,231.54	577,030.18	585,062.27
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Total Other Taxes	149,239.69	127,728.77	149,239.69	153,900.00	127,728.77	1,904,879.43	1,789,200.28
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Income Taxes							
Current Federal	1,363,894.58	1,087,655.00CR	1,363,894.58	125,600.00CR	1,087,655.00CR	1,532,931.86CR	14,399.00
Current State	115,014.35	118,826.00CR	115,014.35	.00	118,826.00CR	282,789.47CR	177,514.00
Deferred Federal & State	857,433.39CR	1,175,881.00	857,433.39CR	.00	1,175,881.00	3,905,642.15	1,760,831.00
Investment Tax Credit-Net	2,550.00CR	2,775.00CR	2,550.00CR	.00	2,775.00CR	31,950.00CR	34,549.98CR
	----------------	----------------	----------------	----------------	----------------	----------------	----------------
Total Income Taxes	618,925.54	33,375.00CR	618,925.54	125,600.00CR	33,375.00CR	2,057,970.82	1,918,194.02
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TOTAL OPERATING EXPENSES	6,033,372.61	9,334,235.87	6,033,372.61	2,690,700.00	9,334,235.87	50,906,442.93	60,750,538.06
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DELTA NATURAL GAS CO., INC. JBSIDIARIES

Income Statement - Delta

December 01, 2009 - December 31, 2009

	Current Month Amount	Last Year Curr Month Amount	Current Y-T-D Amount	Current Year Y-T-D Budget	Last Year Y-T-D Amount	12 Month Y-T-D Amount	Previous 12 Month Amount
OPERATING INCOME	1,372,258.11CR	1,197,365.10CR	1,372,258.11CR	188,500.00CR	1,197,365.10CR	6,930,583.78CR	8,573,173.07CR
Income Before Interest Charges	1,372,258.11CR	1,197,365.10CR	1,372,258.11CR	188,500.00CR	1,197,365.10CR	6,930,583.78CR	8,573,173.07CR
INTEREST CHARGES							
Interest On Long-Term Debt	300,282.50	304,695.84	300,282.50	303,200.00	304,695.84	3,622,780.28	3,668,683.13
Interest On Short-Term Debt	5,319.74	18,147.36	5,319.74	55,300.00	18,147.36	32,287.39	336,450.14
Other Interest	3,101.42	3,097.01	3,101.42	3,100.00	3,097.01	33,270.92	33,142.87
Amortization of Debt Expense	32,271.88	32,271.88	32,271.88	32,300.00	32,271.88	387,262.56	387,265.56
Total Interest Charges	340,975.54	358,212.09	340,975.54	393,900.00	358,212.09	4,075,601.15	4,425,541.70
NET INCOME	1,031,282.57CR	839,153.01CR	1,031,282.57CR	205,400.00	839,153.01CR	2,854,982.63CR	4,147,631.37CR

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(s)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Securities and Exchange Commission's annual report for the most recent two (2) years, Form 10-Ks and any Form 8-Ks issued within the past two (2) years, and Form 10-Qs issued during the past six (6) quarters updated as current information becomes available.

Response:

See attached.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2008

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to _______

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact Name of Registrant as Specified in its Charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky **(Address of Principal Executive Offices)**	**40391** **(Zip Code)**

859-744-6171
(Registrant's Telephone Number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the Issuer's classes of common stock, as of the latest practicable date.

3,291,557 Shares of Common Stock, Par Value $1.00 Per Share, Outstanding as of March 31, 2008.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Nine Months Ended March 31, 2008	Nine Months Ended March 31, 2007	Twelve Months Ended March 31, 2008	Twelve Months Ended March 31, 2007
OPERATING REVENUES	$ 48,396,125	$ 41,022,436	$ 90,098,714	$ 82,570,003	$ 105,697,104	$ 96,996,523
OPERATING EXPENSES						
Purchased gas	$ 33,707,814	$ 28,764,326	$60,952,455	$ 56,060,518	$ 70,952,306	$ 65,672,857
Operation and maintenance	3,384,612	3,432,718	9,470,490	9,164,134	12,890,964	12,504,049
Depreciation and amortization	929,256	1,209,638	3,231,574	3,425,719	4,503,494	4,502,695
Taxes other than income taxes	490,007	474,934	1,372,996	1,369,372	1,861,358	1,808,701
Total operating expenses	$ 38,511,689	$ 33,881,616	$75,027,515	$ 70,019,743	$ 90,208,122	$ 84,488,302
OPERATING INCOME	$ 9,884,436	$ 7,140,820	$15,071,199	$ 12,550,260	$ 15,488,982	$ 12,508,221
OTHER INCOME AND DEDUCTIONS, NET	16,963	21,956	36,362	62,220	108,408	216,102
INTEREST CHARGES	1,189,518	1,173,197	3,729,443	3,605,924	4,770,781	4,884,620
NET INCOME BEFORE INCOME TAXES	$ 8,711,881	$ 5,989,579	$11,378,118	$ 9,006,556	$ 10,826,609	$ 7,839,703
INCOME TAX EXPENSE	3,290,773	2,324,250	4,312,670	3,497,150	3,972,220	2,964,350
NET INCOME	$ 5,421,108	$ 3,665,329	$ 7,065,448	$ 5,509,406	$ 6,854,389	$ 4,875,353
BASIC AND DILUTED EARNINGS PER COMMON SHARE	$ 1.65	$ 1.12	$ 2.15	$ 1.69	$ 2.09	$ 1.50
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTAND-ING (BASIC AND DILUTED)	3,288,205	3,269,289	3,283,147	3,263,194	3,280,809	3,260,442
DIVIDENDS DECLARED PER COMMON SHARE	$ .31	$ .305	$ .93	$ .915	$ 1.235	$ 1.215

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	March 31, 2008	June 30, 2007	March 31, 2007
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 1,944,259	$ 187,820	$ 1,615,077
Accounts receivable, less accumulated provisions for doubtful accounts of $420,000, $300,000 and $483,000, respectively	19,860,374	7,389,993	18,070,779
Gas in storage, at average cost	3,315,149	11,841,791	2,145,864
Deferred gas costs	1,900,797	2,941,826	826,698
Materials and supplies, at average cost	510,897	559,087	852,871
Prepayments	1,562,618	2,629,682	1,524,239
Total current assets	$ 29,094,094	$ 25,550,199	$ 25,035,528
PROPERTY, PLANT AND EQUIPMENT	$ 190,556,364	$ 187,148,032	$ 186,550,256
Less-Accumulated provision for depreciation	(66,989,321)	(64,879,205)	(64,166,120)
Net property, plant and equipment	$ 123,567,043	$ 122,268,827	$ 122,384,136
OTHER ASSETS			
Cash surrender value of officers' life insurance	$ 425,609	$ 425,609	$ 379,661
Note receivable from officer	-	-	44,000
Prepaid pension cost	883,123	951,571	5,028,666
Regulatory assets	8,150,894	8,220,590	4,175,131
Unamortized debt expense and other	2,886,787	2,984,154	3,027,092
Total other assets	$ 12,346,413	$ 12,581,924	$ 12,654,550
Total assets	$ 165,007,550	$ 160,400,950	$ 160,074,214

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	March 31, 2008	June 30, 2007	March 31, 2007
LIABILITIES AND COMMON SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 7,080,342	$ 10,299,066	$ 7,500,711
Notes payable	3,287,182	4,189,918	3,803,634
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	4,358,968	973,651	3,379,901
Customers' deposits	612,802	482,446	594,863
Accrued interest on debt	862,990	865,871	858,695
Accrued vacation	679,701	702,521	676,292
Deferred income taxes	935,804	1,273,000	701,000
Other liabilities	412,607	459,651	406,924
Total current liabilities	$ 19,430,396	$ 20,446,124	$ 19,122,020
LONG-TERM DEBT	$ 58,402,000	$ 58,625,000	$ 58,645,000
DEFERRED CREDITS AND OTHER			
Deferred income taxes	$ 23,816,043	$ 22,467,900	$ 22,176,088
Investment tax credits	186,750	213,600	222,850
Regulatory liabilities	2,305,714	2,503,256	2,468,022
Asset retirement obligations and other	2,132,816	1,716,599	1,916,195
Total deferred credits and other	$ 28,441,323	$ 26,901,355	$ 26,783,155
COMMITMENTS AND CONTINGENCIES (Notes 8 and 9)			
Total liabilities	$ 106,273,719	$ 105,972,479	$ 104,550,175
COMMON SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value)	$ 3,291,557	$ 3,277,106	$ 3,272,687
Premium on common shares	43,855,846	43,508,979	43,399,559
Retained earnings	11,586,428	7,642,386	8,851,793
Total common shareholders' equity	$ 58,733,831	$ 54,428,471	$ 55,524,039
Total liabilities and common shareholders' equity	$ 165,007,550	$ 160,400,950	$ 160,074,214

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(UNAUDITED)

	Nine Months Ended March 31,		Twelve Months Ended March 31,	
	2008	2007	2008	2007
COMMON SHARES				
Balance, beginning of period	$ 3,277,106	$ 3,256,043	$ 3,272,687	$ 3,250,768
Dividend reinvestment and stock purchase plan	14,451	16,644	18,870	21,919
Balance, end of period	$ 3,291,557	$ 3,272,687	$ 3,291,557	$ 3,272,687
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 43,508,979	$ 43,025,733	$ 43,399,559	$ 42,900,010
Dividend reinvestment and stock purchase plan	346,867	373,826	456,287	499,549
Balance, end of period	$ 43,855,846	$ 43,399,559	$ 43,855,846	$ 43,399,559
RETAINED EARNINGS				
Balance, beginning of period	$ 7,642,386	$ 6,327,948	$ 8,851,793	$ 7,937,485
Adoption of FASB Interpretation No. 48	(68,630)	-	(68,630)	-
Beginning retained earnings, as adjusted	$ 7,573,756	$ 6,327,948	$ 8,783,163	$ 7,937,485
Net income	7,065,448	5,509,406	6,854,389	4,875,353
Cash dividends declared on common shares (See Consolidated Statements of Income for rates)	(3,052,776)	(2,985,561)	(4,051,124)	(3,961,045)
Balance, end of period	$ 11,586,428	$ 8,851,793	$ 11,586,428	$ 8,851,793
COMMON SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 54,428,471	$ 52,609,724	$ 55,524,039	$ 54,088,263
Adoption of FASB Interpretation No. 48	(68,630)	-	(68,630)	-
Beginning retained earnings, as adjusted	$ 54,359,841	$ 52,609,724	$ 55,455,409	$ 54,088,263
Net income	$ 7,065,448	$ 5,509,406	$ 6,854,389	$ 4,875,353
Issuance of common stock	361,318	390,470	475,157	521,468
Dividends on common stock	(3,052,776)	(2,985,561)	(4,051,124)	(3,961,045)
Balance, end of period	$ 58,733,831	$ 55,524,039	$ 58,733,831	$ 55,524,039

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended March 31		Twelve Months Ended December 31	
	2008	2007	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 7,065,448	$ 5,509,406	$ 6,854,389	$ 4,875,353
Adjustments to reconcile net income to net cash from operating activities				
Depreciation and amortization	3,594,421	3,770,883	4,981,458	5,063,294
Deferred income taxes and investment tax credits	873,847	1,417,138	1,802,009	2,616,954
Other, net	(153,058)	(146,061)	(212,823)	(156,865)
Decrease (increase) in assets	(2,906,037)	(907,196)	(3,928,431)	5,241,679
Increase (decrease) in liabilities	689,060	3,257,080	1,268,119	(197,199)
Net cash provided by operating activities	$ 9,163,681	$ 12,901,250	$ 10,764,721	$ 17,443,216
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (3,847,977)	$ (5,536,987)	$ (6,410,292)	$ (7,594,052)
Proceeds from sale of property, plant and equipment	257,929	94,567	310,172	157,510
Net cash used in investing activities	$ (3,590,048)	$ (5,442,420)	$ (6,100,120)	$ (7,436,542)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common stock	$ (3,052,776)	$ (2,985,561)	$ (4,051,124)	$ (3,961,045)
Issuance of common stock	361,318	390,470	475,157	521,468
Long-term debt issuance expense	-	(10,970)	-	(2,321,144)
Issuance of long-term debt	-	-	-	40,000,000
Repayment of long-term debt	(223,000)	(145,000)	(243,000)	(33,986,000)
Issuance of notes payable	57,005,260	45,547,004	62,976,861	61,626,943
Repayment of notes payable	(57,907,996)	(48,789,804)	(63,493,313)	(70,492,860)
Net cash used in financing activities	$ (3,817,194)	$ (5,993,861)	$ (4,335,419)	$ (8,612,638)
NET INCREASE IN CASH AND CASH EQUIVALENTS	$ 1,756,439	$ 1,464,969	$ 329,182	$ 1,394,036
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	187,820	150,108	1,615,077	221,041
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 1,944,259	$ 1,615,077	$ 1,944,259	$ 1,615,077

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 39,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(2) In our opinion, all adjustments necessary for a fair presentation of the unaudited results of operations for the three, nine and twelve months ended March 31, 2008 and 2007 are included. All such adjustments are accruals of a normal and recurring nature. The results of operations for the periods ended March 31, 2008 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve months ended financial information is provided for additional information only. The accompanying consolidated financial statements are unaudited and should be read in conjunction with the financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended June 30, 2007.

(3) In July 2006, the FASB issued Interpretation No. 48, entitled Accounting for Uncertainty in Income Taxes, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Financial Accounting Standards Board Statement No. 109. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

We adopted the provisions of Interpretation No. 48 on July 1, 2007. The adoption of Interpretation No. 48 resulted in an adjustment to beginning retained earnings of $68,000. At adoption, the total amount of gross unrecognized tax benefits for uncertain tax positions, including positions impacting only the timing of tax benefits, was $668,000, of which $97,000 related to interest.

The liability for unrecognized tax benefits expected to be recognized within the next twelve months has been presented in accrued taxes as a reduction to prepaid taxes which is included in prepayments on the March 31, 2008 Consolidated Balance Sheet. The liability for unrecognized tax benefits not expected to be recognized within the next twelve months has been presented in asset retirement obligations and other on the March 31, 2008 Consolidated Balance Sheet. Interest and penalties on tax uncertainties are classified in income tax expense on the Consolidated Statements of Income. During the quarter ended March 31, 2008, the statute of limitations expired for our 2004 Federal and 2003 Kentucky tax years. As a result, our unrecognized tax positions decreased $24,000, which primarily related to interest accrued on timing differences. The unrecognized tax positions decreased an additional $43,000 due to filing an automatic method change with the Internal Revenue Service related to one of our unrecognized positions. For the three, nine and twelve months ended March 31, 2008, an additional $11,000, $28,000 and $28,000, respectively, of interest was accrued which increased the liability for unrecognized tax benefits.

The amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $90,000. It is reasonably possible that the amount of unrecognized tax benefits will change in the next 12 months. However, it is not expected that such change will have a significant impact on our results of operations or financial position. We file income tax returns in the federal and Kentucky jurisdictions. Tax years previous to June 30, 2005 and June 30, 2004 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(4) We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the latest date of each meter reading cycle to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	March 31, 2008	June 30, 2007	March 31, 2007
Unbilled revenues ($)	6,041	1,058	3,437
Unbilled gas costs ($)	3,763	497	1,899
Unbilled volumes (Mcf)	360	48	220

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(5) Net pension costs for our trusteed, noncontributory defined benefit pension plan for the periods ended March 31 include the following:

	Three Months Ended March 31,		Nine Months Ended March 31,		Twelve Months Ended March 31,	
($000)	2008	2007	2008	2007	2008	2007
Service cost	187	179	561	537	740	716
Interest cost	187	175	559	525	734	700
Expected return on plan assets	(247)	(249)	(740)	(747)	(989)	(996)
Amortization of unrecognized net loss	62	58	188	174	246	233
Amortization of prior service cost	(21)	(21)	(65)	(63)	(86)	(86)
Net periodic benefit cost	168	142	503	426	645	567

(6) Our note receivable from an officer on the accompanying March 31, 2007 Consolidated Balance Sheet relates to a $160,000 loan to Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer.

(7) The current available bank line of credit with Branch Banking and Trust Company is $40,000,000, of which $3,287,000, $4,190,000 and $3,804,000 were borrowed having a weighted average interest rate of 3.86%, 6.32% and 6.32% as of March 31, 2008, June 30, 2007 and March 31, 2007, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The bank line of credit extends through October 31, 2009.

Our bank line of credit agreement and the indentures relating to all of our publicly held debentures and insured quarterly notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all debentures and insured quarterly notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the debentures and insured quarterly notes. We were not in default on any of our bank line of credit, debentures or insured quarterly notes during any period presented.

(8) We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum

payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. If the change in ownership occurred on March 31, 2008 and lump sum payments were made to all four officers in accordance with the agreements, approximately $3.0 million would be paid in addition to the continuation of specified benefits for up to five years.

(9) We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

(10) The Kentucky Public Service Commission exercises regulatory authority over our natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge for these services. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas distribution and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. The test year for the case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007, but the implementation of the proposed rates was suspended until October 20, 2007.

During October 2007, we reached a settlement agreement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

(11) Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the distribution or transportation of natural gas. Price risk for the regulated business is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2007. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenue and expense are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown below for the periods:

($000)	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Nine Months Ended March 31, 2008	Nine Months Ended March 31, 2007	Twelve Months Ended March 31, 2008	Twelve Months Ended March 31, 2007
Operating Revenues						
Regulated						
External customers	27,121	22,737	48,812	45,228	57,083	52,372
Intersegment	1,386	1,216	3,168	2,939	3,872	3,665
Total regulated	28,507	23,953	51,980	48,167	60,955	56,037
Non-regulated						
External customers	21,275	18,285	41,287	37,342	48,614	44,625
Eliminations for intersegment	(1,386)	(1,216)	(3,168)	(2,939)	(3,872)	(3,665)
Total operating revenues	48,396	41,022	90,099	82,570	105,697	96,997
Net Income						
Regulated	3,483	2,302	3,889	2,604	3,707	1,891
Non-regulated	1,938	1,363	3,176	2,905	3,147	2,984
Total net income	5,421	3,665	7,065	5,509	6,854	4,875

(12) In September 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 requires employers who sponsor defined benefit plans to recognize the funded status of the plan and gains and losses not previously recognized in net periodic benefit cost in the sponsor's financial statements in fiscal years ending after December 15, 2006. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years ending after December 15, 2008.

On June 30, 2007, we adopted the requirement to recognize the funded status of our defined benefit plan on our Consolidated Balance Sheet. The requirement to measure plan assets and benefit obligations as of our fiscal year-end shall be effective for our fiscal 2009 year-end. We do not expect this requirement to have a material impact on our results of operations or financial position.

(13) In September 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures and in February 2007, issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. Both statements are effective for fiscal years beginning after November 15, 2007. The statements define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. We do not expect these statements, which shall be effective for our 2009 fiscal year, to have a material impact on our results of operations or financial position.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE MARCH 31, 2008 OVERVIEW AND FUTURE OUTLOOK

Consolidated net income per share for the nine months ended March 31, 2008 of $2.15 increased $.46 per share from the net income per share for the nine months ended March 31, 2007 of $1.69. The increase is due to a $1,285,000 increase in our regulated net income as a result of the implementation of new base rates, as approved by the Kentucky Public Service Commission effective October 20, 2007. Additionally, our non-regulated net income increased $271,000 due to a combination of higher prices and increase in volumes sold.

The results for the year ended June 30, 2008 should continue to be impacted by the new base rates implemented effective October 20, 2007, which were designed to annually generate an additional $3,920,000 of revenue.

We expect our non-regulated segment to continue to contribute to our consolidated net income in fiscal 2008, as in recent years, based on contracts currently in place. Future profitability of the non-regulated segment, though, is dependent on the business plans of a few large customers and the market prices of natural gas, which are both out of our control. If natural gas prices decrease considerably, we expect to experience a corresponding decrease in our non-regulated segment margins.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable decreased to $3,287,000 at March 31, 2008, compared to $4,190,000 at June 30, 2007 and $3,804,000 at March 31, 2007. These decreases reflect the seasonal nature of our sales and cash needs. Our liquidity is impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $3,848,000 and $6,410,000 during the nine and twelve months ended March 31, 2008, respectively. During the nine and twelve months ended March 31, 2008 and 2007 cash provided by operating activities exceeded our capital expenditures. However, in periods when cash provided by operating activities is not sufficient to meet our capital requirements, we finance the balance of our capital expenditures on an interim basis through this bank line of credit. We periodically repay our short-term borrowings under our bank line of credit by using the net proceeds from the sale of long-term debt and equity securities, as was done in April, 2006 by a $3,830,000 repayment in connection with the issuance of the 5.75% Insured Quarterly Notes.

Long-term debt decreased to $58,402,000 at March 31, 2008, compared with $58,625,000 at June 30, 2007 and $58,645,000 at March 31, 2007. These decreases resulted from the redemption of the Debentures and Insured Quarterly Notes, which allow for limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents increased to $1,944,000 at March 31, 2008, compared with $188,000 at June 30, 2007 and $1,615,000 at March 31, 2007. These increases in cash and cash equivalents for nine and twelve months ended March 31, 2008 are summarized in the following table:

	Nine Months Ended March 31,		Twelve Months Ended March 31,	
($000)	2008	2007	2008	2007
Provided by operating activities	9,163	12,901	10,764	17,443
Used in investing activities	(3,590)	(5,442)	(6,100)	(7,437)
Used in financing activities	(3,817)	(5,994)	(4,335)	(8,612)
Increase in cash and cash equivalents	1,756	1,465	329	1,394

For the nine months ended March 31, 2008, $3,737,000 less cash was provided by operating activities as compared with the nine months ended March 31, 2007. Due to increased gas prices, volumes purchased and the timing of payables, $8,738,000 more cash was used for the purchase of gas. This increase in cash paid for gas was partially offset by a $4,293,000 increase in cash received from customers due to increased sales, net of increased customer receivables.

For the twelve months ended March 31, 2008, $6,678,000 less cash was provided by operating activities compared with the twelve months ended March 31, 2007. Due to increased gas prices, volumes purchased and the timing of payables, $11,444,000 more cash was used for the purchase of gas. This increase in cash paid for gas was partially offset by a $4,981,000 increase in cash received from customers due to increased sales, net of increased customer receivables.

Changes in cash used in investing activities result primarily from the change in level of capital expenditures between periods.

For the nine months ended March 31, 2008, $2,177,000 less cash was used in financing activities as compared with the nine months ended March 31, 2007, primarily due to decreased net repayments on our bank line of credit during the same time period.

For the twelve months ended March 31, 2008, $4,278,000 less cash was used in financing activities as compared with the twelve months ended March 31, 2007. During the twelve months ended March 31, 2007 we refinanced a portion of our long-term debt and the net proceeds from the refinancing were used to repay a portion of our bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2008 to be $6.3 million.

Sufficiency of Future Cash Flows

To the extent that internally generated cash is not sufficient to satisfy operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit is $40,000,000, of which $3,287,000 was borrowed at March 31, 2008, and was classified as notes payable in the accompanying Consolidated Balance Sheets. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009.

We expect that internally generated cash, coupled with short and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices and we continuously monitor our need to file rate requests with the Kentucky Public Service Commission for general rate increases for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. This rate case requested a return on common equity of 12.1%. The test year for the case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007. The Kentucky Public Service Commission suspended the implementation of the proposed rates until October 20, 2007.

During October 2007, we reached a settlement agreement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenue from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas, which can be derived directly from our Consolidated Statements of Income. Operating income, as presented on the Consolidated Statements of Income, is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3 for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three, nine and twelve months ended March 31, 2008 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

	2008 compared to 2007		
($000)	Three Months Ended March 31,	Nine Months Ended March 31,	Twelve Months Ended March 31,
Increase (decrease) in regulated gross margins			
Gas sales	1,023	1,131	1,676
On-system transportation	163	115	75
Off-system transportation	218	742	1,015
Other	(145)	(206)	(196)
Total	1,259	1,782	2,570
Increase (decrease) in non-regulated gross margins			
Gas sales	1,143	770	754
Other	28	86	97
Total	1,171	856	851
Increase in consolidated gross margins	2,430	2,638	3,421
Percentage increase (decrease) in regulated volumes			
Gas sales	1.5	(4.1)	(0.8)
On-system transportation	1.9	(4.9)	(5.7)
Off-system transportation	16.6	29.7	29.5
Percentage increase in non-regulated gas sales volumes	2.5	5.6	4.4

Heating degree days were 102%, 95% and 95% of normal thirty year average temperatures for the three, nine and twelve months ended March 31, 2008, respectively, as compared with 94%, 94% and 93% of normal temperatures in the 2007 periods. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended March 31, 2008, consolidated gross margins increased $2,430,000 (20%) due to increases in our regulated and non-regulated gross margins of $1,259,000 (15%) and $1,171,000 (33%), respectively. Our regulated margin for gas sales increased $1,023,000 (13%) primarily due to increased base rates which became effective October 20, 2007. Our regulated off-system transportation gross margins increased $218,000 due to a 17% increase in volumes transported. Our non-regulated gross margins increased $1,171,000 (33%) due to higher sales prices.

For the nine months ended March 31, 2008, consolidated gross margins increased $2,638,000 (10%) due to increases in our regulated and non-regulated gross margins of $1,782,000 (10%) and $856,000 (11%), respectively. Our regulated margin for gas sales increased $1,131,000 (7%) due to increased base rates which became effective October 20, 2007. The new base rates allocated 68% of the increase to the monthly customer charge to partially decouple rates from volumes. Our regulated off-system transportation gross margins increased $742,000 due to a

30% increase in volumes transported. Our non-regulated gross margins increased $856,000 (11%) due to increased prices and a 6% increase in volumes sold.

For the twelve months ended March 31, 2008, consolidated gross margins increased $3,421,000 (11%) due to increases in our regulated and non-regulated gross margins of $2,570,000 (12%) and $851,000 (9%), respectively. Our regulated margin for gas sales increased $1,676,000 (9%) due to increased base rates that became effective October 20, 2007. Our regulated off-system transportation gross margins increased $1,015,000 due to a 30% increase in volumes transported. Our non-regulated gross margins increased $851,000 (9%) due to increased prices and a 4% increase in volumes transported.

Depreciation and Amortization

For the three months ended March 31, 2008, depreciation and amortization decreased $281,000 (23%) due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decrease was partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Income and Deductions, Net

For the twelve months ended March 31, 2008, other income and deductions, net decreased $108,000 (50%). The decrease was due to investment income received during the twelve months ended March 31, 2007 on cash invested when we refinanced a portion of our long-term debt.

Income Taxes

For the three, nine and twelve months ended March 31, 2008, income taxes increased $967,000 (42%), $816,000 (23%) and $1,008,000 (34%), respectively. The changes in income taxes are attributable to changes in net income before income taxes for the same time periods.

Basic and Diluted Earnings Per Common Share

For the three, nine and twelve months ended March 31, 2008 and 2007, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement of Financial Accounting Standards No. 133, entitled Accounting for Derivative Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balances on our bank line of credit were \$3,287,000, \$4,190,000 and \$3,804,000 on March 31, 2008, June 30, 2007 and March 31, 2007, respectively. The weighted average interest rates on our bank line of credit were 3.86%, 6.32%, and 6.32% on March 31, 2008, June 30, 2007 and March 31, 2007, respectively. Based on the amounts of our outstanding bank line of credit on March 31, 2008, June 30, 2007 and March 31, 2007, a one percent (one hundred basis point) increase in our average interest rates would result in decreases in our annual pre-tax net income of \$33,000, \$42,000 and \$38,000, respectively.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's ("SEC's") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2008, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC's rules and forms.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended March 31, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: May 5, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 5, 2008

By: /s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 5, 2008

By: /s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

May 5, 2008

By: /s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending March 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

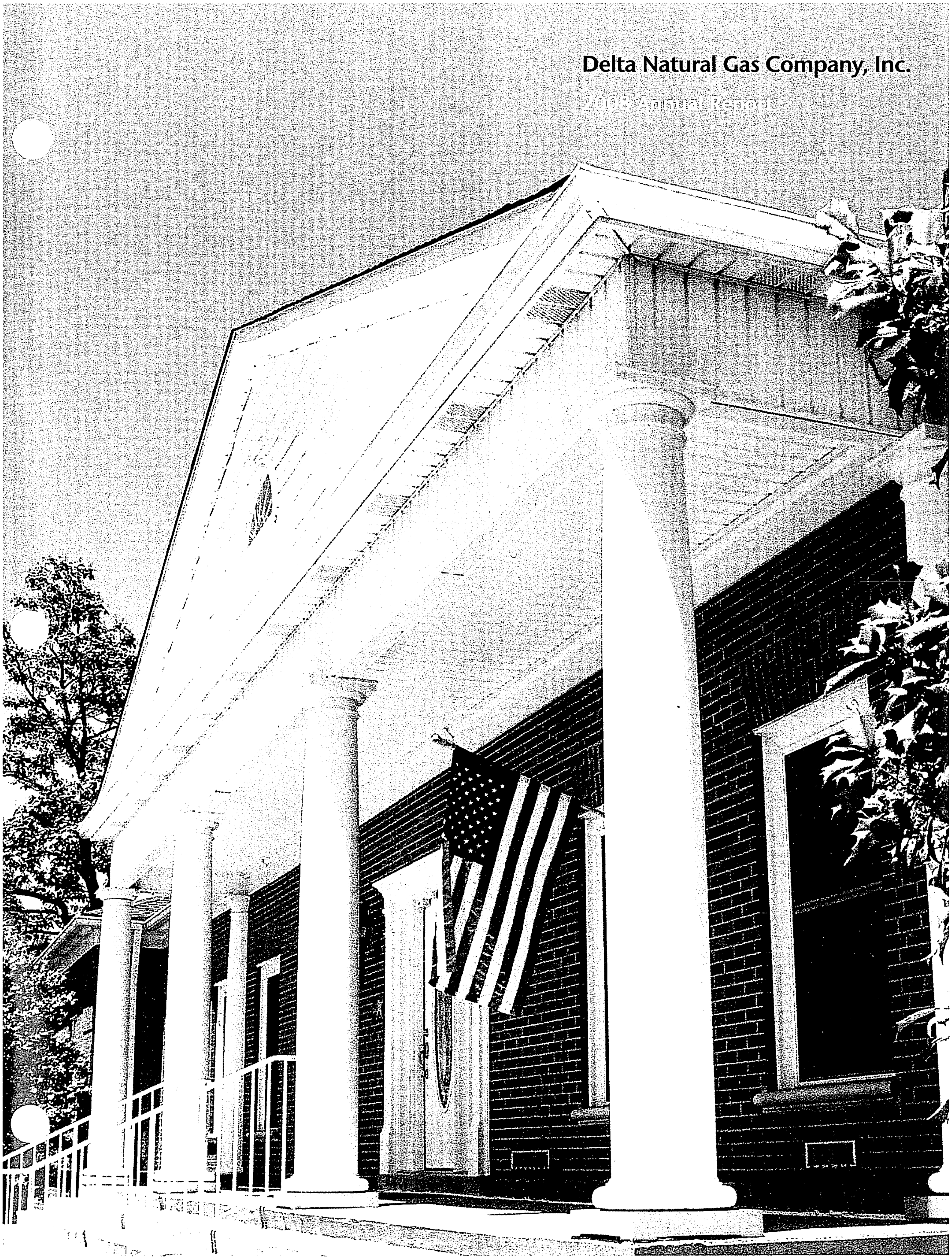
(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

May 5, 2008

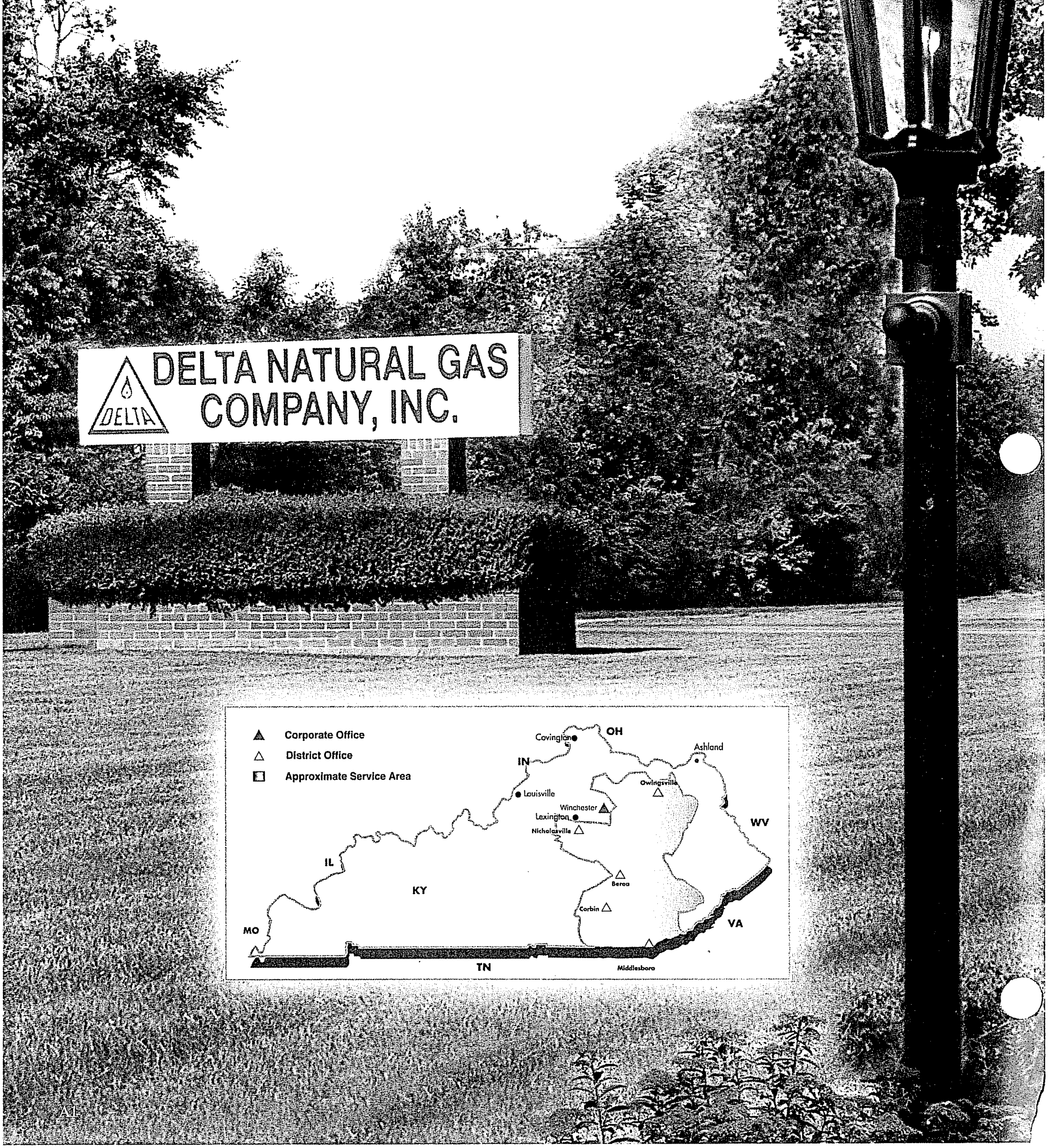
By: /s/John B. Brown
John B. Brown
Chief Financial Officer,
Treasurer and Secretary

Delta Natural Gas Company, Inc.

2008 Annual Report



Delta will provide premier natural gas services while having a positive impact on customers, employees and shareholders.



To Our Shareholders

This year's annual report cover reflects the front entrance to our corporate headquarters in Winchester, Kentucky. We are starting into our 60th year at Delta Natural Gas this year. We appreciate all investors that have displayed confidence in the Company by becoming one of its owners. We welcome shareholders to visit with us at any time, but we particularly welcome you to visit us for our 2008 annual meeting of shareholders to be held at our Winchester office on November 20, 2008.

This has been another challenging yet rewarding year for our Company, and all of our employees responded to the demands of 2008 by continuing to perform at a very high level. I want to thank each of them for doing their job well and collectively helping Delta to attain our improved results.

Our earnings increased from $1.62 per common share last year to $2.08 per common share this year. Despite warmer than normal weather, our regulated operations' financial results improved as a result of the rate case we filed in 2007 that was concluded in October, 2007. We continued to increase our transportation business and this led to our total throughput exceeding 20 billion cubic feet in 2008. Our unregulated subsidiaries continued to have good results and thus added to our 2008 performance.

I appreciate so much our Board of Directors and the dedication they display in carrying out their oversight duties for the Company. Their counsel and judgement are of significant benefit to Delta. They displayed their confidence in the Company's future by increasing the quarterly dividend from $.31 per share to $.32 per share at their Board meeting held on August 22. This represents a $.04 per share, or 3.2%, increase on an annual basis.

Don Crowe completed serving Delta as a member of our Board of Directors in November, 2007. Don had been a member of Delta's Board since 1966. We express our sincere thanks to Don for his many years of valuable service to the Company. His contributions are greatly appreciated and we extend to Don our gratitude and very best wishes.

We welcomed our newest Board member, Linda Breathitt, at our November, 2007 Annual Meeting of Shareholders. Linda is a former Chair of the Kentucky Public Service Commission as well as a former member of the Federal Energy Regulatory Commission. I am so very pleased to have Linda on our Board of Directors and look forward to her continued contributions to Delta.

We at Delta strive to provide the best quality of service possible to our customers while doing the best we can for all our employees and for you, our owners. As I complete my 30th year with Delta later this year, 23 of them as President and Chief Executive Officer, I am thankful for being blessed with the opportunity to work with Delta's trained, dedicated employees. I look forward to my continuing involvement in our Kentucky-based company that is a part of the important energy segment of our country.

Sincerely,

Glenn R. Jennings

Glenn R. Jennings
Chairman of the Board, President
and Chief Executive Officer

August 25, 2008

Selected Financial Information

For the Years Ended June 30,	2008	2007	2006	2005	2004
Summary of Operations ($)					
Operating revenues (a) (b)	**112,657,117**	98,168,391	117,247,144	84,181,233	79,193,614
Operating income (a) (b)	**15,663,736**	12,968,043	12,757,507	12,490,127	10,532,904
Net income (a) (b)	**6,829,868**	5,298,347	5,024,635	4,998,619	3,838,059
Basic and diluted earnings per common share (a) (b)	**2.08**	1.62	1.55	1.55	1.20
Dividends declared per common share	**1.24**	1.22	1.20	1.18	1.18
Total Assets ($)	**170,814,856**	160,400,950	155,554,125	144,762,217	138,372,129
Capitalization ($)					
Common shareholders' equity	**57,593,585**	54,428,471	52,609,724	50,799,454	48,830,161
Long-term debt (c)	**58,318,000**	58,625,000	58,790,000	52,707,000	53,049,000
Total capitalization	**115,911,585**	113,053,471	111,399,724	103,506,454	101,879,161
Short-Term Debt ($) (c) (d)	**8,028,791**	5,389,918	8,246,434	7,609,122	6,388,180
Capital Expenditures	**5,563,667**	8,082,918	7,781,396	5,338,356	8,959,153

(a) We recorded 58,000 Mcf of unbilled sales at June 30, 2005, resulting in non-recurring increases of $1,246,000 in operating revenues, $617,000 in operating income, $379,000 in net income and $.12 in basic and diluted earnings per common share for fiscal 2005.

(b) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and October, 2004, and the rates were designed to generate additional annual revenue of $3,920,000 and $2,756,000, respectively.

(c) During April, 2006, we issued $40,000,000 aggregate principal amount of 5.75% Insured Quarterly Notes due 2021. The net proceeds of the offering were $37,671,000. We used the net proceeds to redeem $23,700,000 and $10,200,000 aggregate principal amount of our 7.15% Debentures due 2018 and 6 5/8% Debentures due 2023, respectively. The remaining net proceeds of $3,830,000 were used to pay down our bank line of credit.

(d) Includes current portion of long-term debt.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

(Mark one)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended June 30, 2008.

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to ________

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	61-0458329
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	**(Zip code)**

859-744-6171

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $1 Par Value	NASDAQ OMX Group

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasonal issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15 (d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "accelerated filer, large accelerated filer and smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recent completed second fiscal quarter. $ 82,978,469

As of August 15, 2008, Delta Natural Gas Company, Inc. had outstanding 3,296,801 shares of common stock $1 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive proxy statement, to be filed with the Commission not later than 120 days after June 30, 2008, is incorporated by reference in Part III of this Report.

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PART I

Item 1. Business

General

We distribute or transport natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We produce a relatively small amount of natural gas from our southeastern Kentucky wells.

We seek to provide dependable, high-quality service to our customers while steadily enhancing value for our shareholders. Our efforts have been focused on developing a balance of regulated and non-regulated businesses to contribute to our earnings by profitably producing, selling and transporting gas in our service territory.

We strive to achieve operational excellence through economical, reliable service and our emphasis on responsiveness to customers. We continue to invest in facilities for the transmission, distribution and storage of natural gas. We believe that our responsiveness to customers and the dependability of the service we provide afford us additional opportunities for growth. While we seek those opportunities, our strategy will continue a conservative approach that seeks to minimize our exposure to market risk arising from fluctuations in the prices of gas.

We operate through two segments, a regulated segment and a non-regulated segment. See Note 14 of the Notes to Consolidated Financial Statements for a discussion of these segments. Through our regulated segment, we distribute natural gas to our retail customers in 23 predominantly rural counties. In addition, our regulated segment transports gas to industrial customers on our system who purchase gas in the open market. Our regulated segment also transports gas on behalf of local producers and other customers not on our distribution system. Our results of operations and financial condition have been strengthened by regulatory developments in recent years, including a $3,920,000 revenue increase from our last rate case, a weather normalization provision, which has reduced fluctuations in our earnings due to variations in weather, and a gas cost recovery clause, which mitigates market risk arising from fluctuations in the price of gas.

We operate our non-regulated segment through three wholly-owned subsidiaries. Two of these subsidiaries, Delta Resources, Inc. and Delgasco, Inc., purchase natural gas in the open market, including from Kentucky producers. We resell this gas to industrial customers on our distribution system and to others not on our system. Our third subsidiary, Enpro, Inc., produces natural gas that is sold in the open market.

Our executive offices are located at 3617 Lexington Road, Winchester, Kentucky 40391. Our telephone number is (859) 744-6171. Our website is www.deltagas.com.

Distribution and Transmission of Natural Gas

The economy of our service area is based principally on coal mining, farming and light industry. The communities we serve typically contain populations of less than 20,000. Our three largest service areas are Nicholasville, Corbin and Berea, Kentucky. In Nicholasville we serve approximately 8,000 customers, in Corbin we serve approximately 6,000 customers, and in Berea we serve approximately 4,000 customers.

During fiscal 2008 we received an order from the Kentucky Public Service Commission, which granted us an increase in the base rates we charge our customers. The order was the result of a settlement agreement we reached with the Kentucky Attorney General in our rate case. The increased rates are designed to generate an additional $3,920,000 in revenue. The increase in rates helped to offset the impact of declining customer usage due to conservation and efficiency, a trend we have experienced the past several years. Some of the communities we serve continue to expand, resulting in growth opportunities for us. Industrial parks have been developed in our service areas, which could result in additional growth in industrial customers as well.

Factors that affect our revenues include rates we charge our customers, our supply cost for the natural gas we purchase for resale, economic conditions in our service areas, weather and competition.

Although the Kentucky Public Service Commission permits us to pass through to our customers changes in the price we must pay for our gas supply, increases in our rates to customers may cause our customers to conserve or to use alternative energy sources.

Our regulated sales are seasonal and temperature-sensitive, since the majority of the gas we sell is used for heating. Variations in the average temperature during the winter impact our revenues year-to-year. The Kentucky Public Service Commission, through our tariff, permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

We compete with alternate sources of energy for our regulated distribution customers. These alternate sources include electricity, coal, oil, propane and wood. Our non-regulated subsidiaries, which sell gas to industrial customers and others, compete with natural gas producers and natural gas marketers for those customers.

Our larger customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supplies would be most likely to consider taking this action. Additionally, some of our industrial customers are able to switch economically to alternative sources of energy. These are competitive concerns that we continue to address.

Some natural gas producers in our service area can access pipeline delivery systems other than ours, which generates competition for our transportation services. We continue our efforts to purchase or transport natural gas that is produced in reasonable proximity to our transportation facilities.

As an active participant in many areas of the natural gas industry, we plan to continue efforts to expand our gas distribution system and customer base. We continue to consider acquisitions of other gas systems, some of which are contiguous to our existing service areas, as well as expansion within our existing service areas.

We anticipate continuing activity in gas production and transportation and plan to pursue and increase these activities wherever practicable. We continue to consider the construction, expansion or acquisition of additional transmission, storage and gathering facilities to provide for increased transportation, enhanced supply and system flexibility.

A single customer, Citizens Gas Utility District, provided $17,087,000, $9,843,000 and $15,422,000 of non-regulated revenues during 2008, 2007 and 2006, respectively, although there is no assurance that revenues from them will continue at these levels. See Note 14 of the Notes to Consolidated Financial Statements.

Gas Supply

We purchase our natural gas from a combination of interstate and Kentucky sources. In our fiscal year ended June 30, 2008, we purchased approximately 99% of our natural gas from interstate sources.

Interstate Gas Supply

We acquire our interstate gas supply from gas marketers. We currently have commodity requirements agreements with Atmos Energy Marketing ("Atmos") for our Columbia Gas Transmission Corporation ("Columbia Gas"), Columbia Gulf Transmission Corporation ("Columbia Gulf"), Tennessee Gas Pipeline ("Tennessee") and Texas Eastern Transmission Corporation ("Texas Eastern") supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. The gas we purchase under these agreements is priced at index-based market prices or at mutually agreed-to fixed prices. The index-based market prices are determined based on the prices published on the first of the month in Platts' Inside FERC's Gas Market Report in the indices that relate to the pipelines through which the gas will be transported, plus or minus an agreed-to fixed price adjustment per million British Thermal Units of gas sold. Consequently, the price we pay for interstate gas is based on current market prices.

Our agreements with Atmos for the Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied service areas continue year to year unless cancelled by either party by written notice at least sixty days prior to the annual anniversary date (April 30) of the agreement.

We also purchase additional interstate natural gas from Atmos, as needed, in addition to our commodity requirements agreements with Atmos. This spot gas purchasing arrangement is pursuant to an agreement with Atmos containing an "evergreen" clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Delta's purchases from Atmos under this spot purchase agreement are generally month-to-month. However, Delta does have the option of forward-pricing gas for one or more months for the upcoming winter season. The price of gas under this agreement is based on current market prices, determined in a similar manner as under the commodity requirements contract with Atmos, with an agreed-to fixed price adjustment per million British Thermal Units purchased. In our fiscal year ended June 30, 2008, approximately 42% of Delta's gas supply was purchased under our agreements with Atmos.

Delta purchases gas from M & B Gas Services, Inc. ("M & B") for injection into our underground natural gas storage field and to supply a portion of our system. We are not obligated to purchase any minimum quantities from M & B nor to purchase gas from M & B for any periods longer than one month at a time. The gas is priced at index-based market prices or at mutually agreed-to fixed prices. Our agreement with M & B may be terminated upon 30 days prior written notice by either party. Any purchase agreements for unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2008, approximately 57% of Delta's gas supply was purchased under our agreement with M & B.

We also purchase interstate natural gas from other gas marketers as needed at either current market prices, determined by industry publications, or at forward market prices.

Transportation of Interstate Gas Supply

Our interstate natural gas supply is transported to us from market hubs, production fields and storage fields by Tennessee, Columbia Gas, Columbia Gulf and Texas Eastern.

Our agreements with Tennessee extend through 2013 and thereafter automatically renew for subsequent five-year terms unless terminated by one of the parties. Tennessee is obligated under these agreements to transport up to 19,600 thousand cubic feet ("Mcf") per day for us. During fiscal 2008, Tennessee transported a total of 1,141,000 Mcf for us under these contracts. Annually, approximately 28% of Delta's supply requirements flow through Tennessee to our points of receipt under our transportation agreements with Tennessee. We have gas storage agreements with Tennessee under the terms of which we reserve a defined storage space in Tennessee's storage fields and we reserve the right to withdraw up to fixed daily volumes. These gas storage agreements terminate on the same schedule as our transportation agreements with Tennessee.

Under our agreements with Columbia Gas and Columbia Gulf, Columbia Gas is obligated to transport, including utilization of our defined storage space as required, up to 12,600 Mcf per day for us, and Columbia Gulf is obligated to transport up to a total of 4,300 Mcf per day for us. During fiscal 2008 Columbia Gas and Columbia Gulf transported for us a total of 588,000 Mcf, or approximately 14% of Delta's supply requirements, under all of our agreements with them. All of our transport agreements with Columbia Gas and Columbia Gulf continue on a year-to-year basis until terminated by one of the parties.

Columbia Gulf also transported additional volumes under agreements it has with M & B to a point of interconnection between Columbia Gulf and us where we purchase the gas to inject into our storage field, as discussed above. The amounts transported and sold to us under the agreement between Columbia Gulf and this gas marketer for fiscal 2008 constituted approximately 57% of Delta's gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the gas to us that we purchase from that marketer to supply our customers' requirements in specific geographic areas. Consequently, Texas Eastern transports a small percentage of our interstate gas supply. In our fiscal year ended June 30, 2008, Texas Eastern transported approximately 17,000 Mcf of natural gas to our system, which constituted less than 1% of our gas supply.

Kentucky Gas Supply

We have an agreement with Chesapeake Appalachia LLC to purchase natural gas on a year-to-year basis unless terminated by one of the parties. We purchased 41,000 Mcf from Chesapeake during fiscal 2008. The price for the gas we purchase from Chesapeake is based on the index price of spot gas delivered to Columbia Gas in the relevant region as reported in Platt's Inside FERC's Gas Market Report, plus a fixed adjustment per million British Thermal units of gas purchased. Chesapeake delivers this gas to our customers directly from its own pipelines.

We own and operate an underground natural gas storage field that we use to store a significant portion of our winter gas supply needs. This storage capability permits us to purchase and store gas during the non-heating months and then withdraw and sell the gas during the peak usage months.

We continue to maintain an active gas supply management program that emphasizes long-term reliability and the pursuit of cost-effective sources of gas for our customers.

Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our regulated natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. The test year for the case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007, but the implementation of the proposed rates was suspended until October 20, 2007.

During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits and promote conservation awareness, and it also provides rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, either our franchises have expired, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible.

Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

Capital Expenditures

Capital expenditures during 2008 were \$5.6 million and for 2009 are estimated to be \$7.9 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are met through the use of internally generated funds and a short-term bank line of credit. The current available line of credit is \$40 million, of which \$6.8 million was borrowed at June 30, 2008.

Present plans are to continue to utilize the short-term bank line of credit to help meet planned capital expenditures and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

Employees

On June 30, 2008, we had 158 full-time employees. We consider our relationship with our employees to be satisfactory. Our employees are not represented by unions nor are they subject to any collective bargaining agreements.

Available Information

We make available free of charge on our Internet website http://www.deltagas.com, our Business Code of Conduct and Ethics, annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains an internet site http://www.sec.gov that contains reports, proxy and information statements and other information regarding Delta. The public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The SEC phone number is 1-800-732-0330.

Consolidated Statistics

For the Years Ended June 30,	**2008**	2007	2006	2005	2004
Average Retail Customers Served					
Residential	**31,520**	31,941	32,601	33,284	33,570
Commercial	**5,107**	5,128	5,154	5,241	5,298
Industrial	**54**	59	59	60	61
Total	**36,681**	37,128	37,814	38,585	38,929
Operating Revenues ($000) (a)					
Residential sales	**30,742**	28,648	35,240	29,172	28,737
Commercial sales	**21,171**	19,339	24,081	18,029	18,719
Industrial sales	**1,707**	1,676	2,356	1,744	1,731
Total regulated sales (b)(c)	**53,620**	49,663	61,677	48,945	49,187
On-system transportation (c)	**4,461**	4,258	4,371	4,312	3,854
Off-system transportation (c)	**3,864**	2,979	2,543	2,099	2,104
Non-regulated sales	**54,438**	44,669	51,904	31,971	27,091
Other	**293**	242	250	211	205
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)	(3,357)	(3,247)
Total	**112,657**	98,168	117,247	84,181	79,194
System Throughput (Million Cu. Ft.) (a)					
Residential sales	**1,695**	1,801	1,764	2,018	2,202
Commercial sales	**1,286**	1,345	1,313	1,381	1,529
Industrial sales	**121**	136	146	158	164
Total regulated sales (b)	**3,102**	3,282	3,223	3,557	3,895
On-system transportation	**4,975**	5,161	5,322	5,273	5,166
Off-system transportation	**12,623**	9,774	8,789	7,194	7,190
Non-regulated sales	**5,394**	4,921	4,398	3,924	3,958
Eliminations for intersegment	**(5,276)**	(4,822)	(4,313)	(3,831)	(3,918)
Total	**20,818**	18,316	17,419	16,117	16,291
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	**54**	56	54	61	66
Lexington, Kentucky Degree Days					
Actual	**4,464**	4,419	4,309	4,293	4,493
Percent of 30 year average	**96**	95	92	92	96

(a) Additional financial information related to our segments can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 14 of the Notes to Consolidated Financial Statements.

(b) 2005 regulated sales includes a $1,246,000 non-recurring increase in revenues due to the recording of 58,000 Mcf of unbilled sales at June 30, 2005.

(c) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and October, 2004, and the base rates were designed to generate additional annual revenue of $3,920,000 and $2,756,000, respectively.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR. Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 76% of our annual gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, which would reduce our revenues and profits. Our weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, only partially mitigates this risk. We adjust our rates to residential and small non-residential customers to reflect variations from thirty-year average weather for our December through April billing cycles.

CHANGES IN FEDERAL REGULATIONS COULD REDUCE THE AVAILABILITY OR INCREASE THE COST OF OUR INTERSTATE GAS SUPPLY. We purchase almost all of our gas supply from interstate sources. For example, in our fiscal year ended June 30, 2008, approximately 99% of our gas supply was purchased from interstate sources. The Federal Energy Regulatory Commission regulates the transmission of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies in a manner that could increase transportation rates or reduce pipeline or storage capacity available to us.

OUR GAS SUPPLY DEPENDS UPON THE AVAILABILITY OF ADEQUATE PIPELINE TRANSPORTATION CAPACITY. We purchase almost all of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of gas.

OUR CUSTOMERS ARE ABLE TO ACQUIRE NATURAL GAS WITHOUT USING OUR DISTRIBUTION SYSTEM. Our larger customers can obtain their natural gas supply by purchasing their natural gas directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution system creates a risk of the loss of large customers and thus could result in lower revenues and profits.

WE FACE REGULATORY UNCERTAINTY AT THE STATE LEVEL. We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our income from operations. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability.

VOLATILITY IN THE PRICE OF NATURAL GAS COULD REDUCE OUR PROFITS. Significant increases in the price of natural gas will likely cause our regulated retail customers to continue to conserve or switch to alternate sources of energy. Any decrease in the volume of gas we sell that is caused by such actions will reduce our revenues and profits. Higher prices also make it more difficult to add new customers. Significant decreases in the price of natural gas will likely cause our non-regulated segment margins to decrease.

WE HAVE NOT HISTORICALLY GENERATED SUFFICIENT CASH FLOWS TO MEET ALL OUR CASH NEEDS. We have made capital expenditures in order to maintain, expand and upgrade our distribution and transmission system. As a result, we have funded a portion of our cash needs through borrowing and by offering new securities into the market. For example, by a combination of increasing our borrowings under our short-term bank line of credit and sales of securities through our dividend reinvestment plan, we generated cash in the amount of $3,116,000 in fiscal 2008. In 2007 cash provided by operating activities was sufficient to meet our financing needs, and we were able to make a net repayment on our short-term bank line of credit in the amount of $2,856,000. Although cash needs vary from year to year, our dependence on external sources of financing creates the risks that our profits could decrease as a result of high capital costs and that lenders could impose onerous and unfavorable terms on us as a condition to granting us loans. We also have the risk that we may not be able to secure external sources of cash necessary to fund our operations.

SUBSTANTIAL OPERATIONAL RISKS ARE INVOLVED IN OPERATING A NATURAL GAS DISTRIBUTION, PIPELINE AND STORAGE SYSTEM AND SUCH OPERATIONAL RISKS COULD REDUCE OUR REVENUES AND INCREASE EXPENSES. There are substantial risks associated with the operation of a natural gas distribution, pipeline and storage system, such as operational hazards and unforeseen interruptions caused by events beyond our control. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage and environmental pollution, which in turn could lead to substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. Liabilities incurred that are not fully covered by insurance could adversely affect our results of operations and financial condition. Additionally, interruptions to the operation of our gas distribution, transmission or storage system caused by such an event could reduce our revenues and increase our expenses.

HURRICANES OR OTHER EXTREME WEATHER COULD INTERRUPT OUR GAS SUPPLY AND INCREASE NATURAL GAS PRICES. Hurricanes or other extreme weather could damage production or transportation facilities, which could result in decreased supplies of natural gas and increased supply costs for us and higher prices for our customers.

CROSS-DEFAULT PROVISIONS IN OUR BORROWING ARRANGEMENTS INCREASE THE CONSEQUENCES OF A DEFAULT ON OUR PART. Each indenture under which our outstanding debt has been issued, and the loan agreement for our bank line of credit, contains a cross-default provision which provides that we will be in default under such indenture or loan agreement in the event of certain defaults under any of the other indentures or loan agreement. Accordingly, should an event of default occur under one of our debt agreements, we face the prospect of being in default under all of our debt agreements and obliged in such instance to satisfy all of our then-outstanding indebtedness. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us.

OUR BORROWING ARRANGEMENTS INCLUDE VARIOUS NEGATIVE COVENANTS THAT RESTRICT OUR ACTIVITIES.

Without bank approval or repaying the bank line of credit, our bank line of credit restricts us from:

- merging with another entity,
- selling a material portion of our assets other than in the ordinary course of business,
- issuing stock which in the aggregate exceeds thirty-five percent (35%) of our outstanding shares of common stock, and
- having any person hold more than twenty percent (20%) of our outstanding shares of common stock.

Our 7.00% Debentures and 5.75% Insured Quarterly Notes restrict us from:

- assuming additional mortgage indebtedness in excess of $5,000,000, and
- paying dividends on our common stock unless our consolidated shareholders' equity minus the value of our intangible assets exceed $25,800,000.

These negative covenants create the risk that we may be unable to take advantage of business and financing opportunities as they arise.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own our corporate headquarters in Winchester, Kentucky. We own ten buildings used for field operations in the cities we serve. Also, we own a building in Laurel County, Kentucky used for training and equipment and materials storage.

We own approximately 2,500 miles of natural gas gathering, transmission, distribution, storage and service lines. These lines range in size up to twelve inches in diameter.

We hold leases for the storage of natural gas under 8,000 acres located in Bell County, Kentucky. We developed this property for the underground storage of natural gas.

We use all the properties described in the three paragraphs immediately above principally in connection with our regulated natural gas distribution, transmission and storage segment. See Note 14 of the Notes to Consolidated Financial Statements for a description of Delta's two business segments.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business.

Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.8 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others and are currently being developed. We have performed no reserve studies on these properties. Enpro produced a total of 162,000 Mcf of natural gas during fiscal 2008 from all the properties described in this paragraph.

A producer is conducting exploration activities on part of Enpro's developed holdings. Enpro reserved the option to participate in wells drilled by this producer and also retained certain working and royalty interests in any production from future wells.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted during the fourth quarter of 2008.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

We have paid cash dividends on our common stock each year since 1964. The frequency and amount of future dividends will depend upon our earnings, financial requirements and other relevant factors, including limitations imposed by the indenture for our Insured Quarterly Notes and Debentures (as described in Note 9 of the Notes to Consolidated Financial Statements).

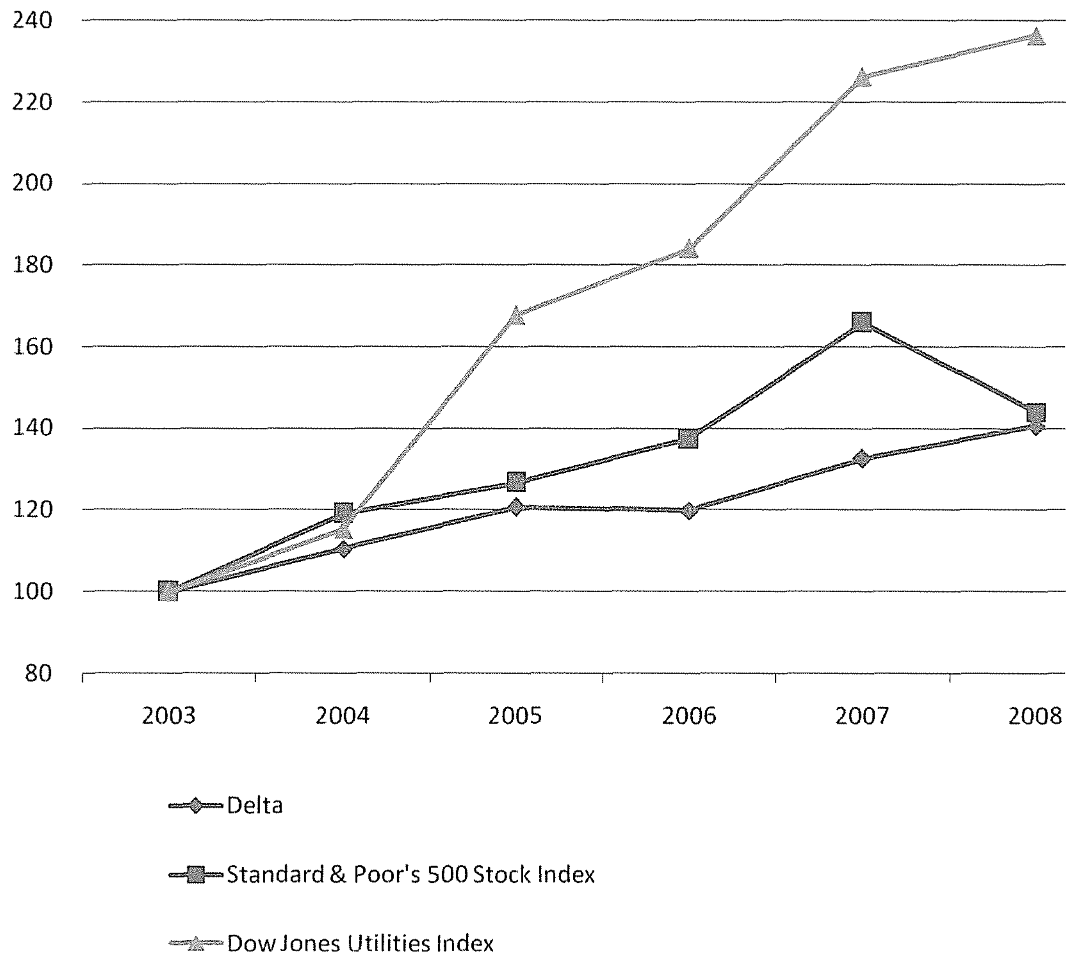
Our common stock is traded on the NASDAQ OMX Group and trades under the symbol "DGAS". There were 1,837 record holders of our common stock as of August 15, 2008. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ OMX Group and the cash dividends declared per share.

	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2008			
First	**25.83**	**23.50**	**.31**
Second	**25.84**	**24.10**	**.31**
Third	**26.73**	**24.11**	**.31**
Fourth	**32.19**	**24.25**	**.31**
Fiscal 2007			
First	25.50	24.11	.305
Second	25.60	24.50	.305
Third	25.48	24.30	.305
Fourth	26.08	23.89	.305

The closing sale prices shown above reflect prices between dealers and do not include markups or markdowns or commissions and may not necessarily represent actual transactions.

Comparison of Five-Year Cumulative Total Shareholder Return

The following graph sets forth a comparison of five year cumulative total shareholder return (equal to dividends plus stock price appreciation) among our common shares, the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index during the past five fiscal years. Information reflected on the graph assumes an investment of $100 on June 30, 2003 in each of our common shares, the Standard & Poor's Stock Index and the Dow Jones Utilities Index. Cumulative total return assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.



	2003	2004	2005	2006	2007	2008
Delta	100.0	110.5	120.6	119.9	132.6	140.7
Standard & Poor's 500 Stock Index	100.0	119.1	126.6	137.6	165.9	144.1
Dow Jones Utilities Index	100.0	115.4	167.8	184.0	226.1	236.4

Item 6. Selected Financial Data

For the Years Ended June 30,	**2008**	2007	2006	2005	2004
Summary of Operations ($)					
Operating revenues (a)(b)	**112,657,117**	98,168,391	117,247,144	84,181,233	79,193,614
Operating income (a)(b)	**15,663,736**	12,968,043	12,757,507	12,490,127	10,532,904
Net income (a)(b)	**6,829,868**	5,298,347	5,024,635	4,998,619	3,838,059
Basic and diluted earnings per common share (a)(b)	**2.08**	1.62	1.55	1.55	1.20
Cash dividends declared per common share	**1.24**	1.22	1.20	1.18	1.18
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,285,464**	3,265,800	3,242,223	3,216,668	3,185,158
Total Assets ($)	**170,814,856**	160,400,950	155,554,125	144,762,217	138,372,129
Capitalization ($)					
Common shareholders' equity	**57,593,585**	54,428,471	52,609,724	50,799,454	48,830,161
Long-term debt (c)	**58,318,000**	58,625,000	58,790,000	52,707,000	53,049,000
Total capitalization	**115,911,585**	113,053,471	111,399,724	103,506,454	101,879,161
Short-Term Debt ($)(c)(d)	**8,028,791**	5,389,918	8,246,434	7,609,122	6,388,180
Other Items ($)					
Capital expenditures	**5,563,667**	8,082,918	7,781,396	5,338,356	8,959,153
Total plant, before accumulated depreciation	**192,127,184**	187,148,032	182,155,110	174,711,253	170,337,427

(a) We recorded 58,000 Mcf of unbilled sales at June 30, 2005, resulting in non-recurring increases of $1,246,000 in operating revenues, $617,000 in operating income, $379,000 in net income and $.12 in basic and diluted earnings per common share for fiscal 2005.

(b) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and October, 2004, and the rates were designed to generate additional annual revenue of $3,920,000 and $2,756,000, respectively.

(c) During April, 2006, we issued $40,000,000 aggregate principal amount of 5.75% Insured Quarterly Notes due 2021. The net proceeds of the offering were $37,671,000. We used the net proceeds to redeem $23,700,000 and $10,200,000 aggregate principal amount of our 7.15% Debentures due 2018 and 6 5/8% Debentures due 2023, respectively. The remaining net proceeds of $3,830,000 were used to pay down our bank line of credit.

(d) Includes current portion of long-term debt.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview of 2008 and Future Outlook

Overview

The following is a discussion of the segments in which we compete, our corporate strategy for the conduct of our business within these segments and significant events that have occurred during 2008. Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production.

Earnings from the regulated segment are primarily influenced by sales and transportation volumes, the rates we charge our customers and the expenses we incur. In order for us to achieve our strategy of maintaining reasonable long-term earnings, cash flow and stock value, we must successfully manage each of these factors. Sales volumes are temperature-sensitive. Our regulated sales volumes in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. The impact of unusual winter temperatures on our revenues is reduced given our ability to adjust our winter rates for residential and small non-residential customers in response to unusual winter temperatures. During 2008 we received an order from the Kentucky Public Service Commission, which granted us an increase in the base rates we charge our customers. The order was the result of a settlement agreement we reached with the Kentucky Attorney General in our rate case. The increased rates became effective in October, 2007 and are designed to annually generate an additional $3,920,000 in revenue.

Our non-regulated segment markets natural gas to large-use customers both on and off Delta's regulated system. We endeavor to enter sales agreements when we can match estimated demand with a supply that provides an acceptable margin.

Earnings per share increased between 2008 and 2007 ($.46 per share) due to the performance of both our regulated and non-regulated segments. The regulated segment experienced increased profitability due to the increased base rates implemented in October, 2007, as well as increased off-system volumes transported. Additionally, our non-regulated segment experienced increased profitability due to an increase in volumes sold.

Future Outlook

In 2009 and beyond, our success will depend, in part, on our ability to maintain a reasonable rate of return in our regulated segment in light of higher gas prices and the resultant conservation by our customers and additional loss of customers switching to alternate energy sources. In 2009, we will be implementing a conservation and efficiency program which is designed to encourage our residential customers to more efficiently use natural gas and to lessen the impact on us from such conservation. The Kentucky Public Service Commission sets the rates we are permitted to charge our customers in the regulated segment. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our regulated services. Through these general rate cases, we seek approval from the Kentucky Public Service Commission to adjust the rates we charge our customers. The regulated segment's largest expense is gas supply, which we are permitted to pass through to our customers. We control remaining expenses through budgeting, approval and review.

We expect our non-regulated segment to continue to contribute to consolidated net income in 2009. Future profitability of the non-regulated segment, though, is dependent on the business plans of a few large customers and the market prices of natural gas, which are both out of our control. If natural gas prices continue to increase, we expect to experience a corresponding increase in our non-regulated margins related to our production activities. If natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

Liquidity and Capital Resources

Sources and Uses of Cash

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $6,829,000 at June 30, 2008, compared with $4,190,000 at June 30, 2007. The $2,639,000 increase is attributable to decreased cash provided by operations. We made capital expenditures of $5,564,000, $8,083,000 and $7,781,000 during the fiscal years ended 2008, 2007 and 2006, respectively. We finance our seasonal cash needs through our bank line of credit. We periodically repay our short-term borrowings under our bank line of credit by using the net proceeds from the sale of long-term debt and equity securities, as was done in 2006 by a $3,830,000 repayment in connection with the issuance of the 5.75% Insured Quarterly Notes.

Long-term debt decreased to $58,318,000 at June 30, 2008, compared with $58,625,000 at June 30, 2007. This $307,000 decrease resulted from provisions in the Debentures and Insured Quarterly Notes allowing limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents increased to $250,000 at June 30, 2008 compared with $188,000 at June 30, 2007. This $62,000 increase in cash and cash equivalents for the year ended June 30, 2008 is compared with the $38,000 and $23,000 increases in cash and cash equivalents for the years ended June 30, 2007 and June 30, 2006, respectively, as shown in the following table:

($000)	**2008**	2007	2006
Provided by operating activities	**6,592**	14,486	6,423
Used in investing activities	**(5,266)**	(7,936)	(7,577)
Provided by (used in) financing activities	**(1,264)**	(6,512)	1,177
Increase in cash and cash equivalents	**62**	38	23

In 2008, $7,894,000 less cash was provided by operating activities as compared to 2007. In 2008, we paid $15,288,000 more for gas due to increased commodity prices, increased volumes purchased and the timing of gas payables. This increase was partially offset due to $7,120,000 more cash received from customers due to increased prices and volumes sold (see related discussion in Results of Operations).

In 2007, cash provided by operating activities increased $8,063,000 as compared to 2006. In 2007, we paid $24,909,000 less for gas, partially offset by $16,052,000 less cash received from customers, both of which are a result of decreased sales volumes and cost of gas over the same time period (see related discussion in Results of Operations).

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

In 2008, $5,248,000 less cash was used in financing activities due to increased net borrowings on our bank line of credit due to a corresponding decrease in cash provided by operating activities.

In 2007, $7,689,000 more cash was used in financing activities due to net repayments on our bank line of credit in the amount of $3,944,000. A further increase in cash used in 2007 in financing activities resulted from $3,480,000 being provided by financing activities in 2006 from the refinancing of the 7.15% and 6 5/8% Debentures. No such refinancing took place in 2007.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2009 to be $7.9 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2008:

	Payments Due by Period				
($000)	2009	2010-2011	2012-2013	After 2013	Total
Interest payments (a)	$ 4,406	$ 7,400	$ 7,400	$ 32,400	$ 51,606
Long-term debt (b)	1,200	2,400	2,400	53,518	59,518
Pension contributions (c)	677	1,000	1,000	8,054	10,731
Gas purchased (d)	898	—	—	—	898
Total contractual obligations	$ 7,181	$ 10,800	$ 10,800	$ 93,972	$ 122,753

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2008 interest payments until the underlying obligation is satisifed. Interest on notes payable represents interest payments expected on the bank line of credit which extends through October 31, 2009. As of June 30, 2008, we have accrued $116,000 on interest related to uncertain tax positions. This amount has been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(b) See Note 9 of the Notes to Consolidated Financial Statements for a description of this debt. The cash obligations represent the maximum annual amount of redemptions to be made to certain holders or their beneficiaries through the debt maturity date. Our long-term debt does not have any sinking fund requirements.

(c) Represents currently projected contributions to the defined benefit plan through 2018, as recommended by our actuary.

(d) As of June 30, 2008, we had three contracts which have minimum purchase obligations whose terms extend through December, 2008. The remainder of our gas purchase contracts are requirement-based contracts or if a minimum purchase obligation exists the contract does not extend for a time period greater than one month.

All of our operating leases are year-to-year and cancelable at our option.

See Note 12 of the Notes to Consolidated Financial Statements for other commitments and contingencies.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short-term and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that cash provided by operations is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit is $40,000,000, of which $6,829,000 was borrowed at June 30, 2008 and classified as notes payable on the accompanying Consolidated Balance Sheet. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices, and we monitor our need to file rate requests with the Kentucky Public Service Commission for a general rate increase for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the use of assumptions and estimates regarding future events, including the likelihood of success of particular investments or initiatives, estimates of future prices or rates, legal and regulatory challenges, and anticipated recovery of costs. Therefore, the possibility exists for materially different reported amounts under different conditions or assumptions. We consider an accounting estimate to be critical if (i) the accounting estimate requires us to make assumptions about matters that were reasonably uncertain at the time the accounting estimate was made, and (ii) changes in the estimate are reasonably likely to occur from period to period.

These critical accounting estimates should be read in conjunction with the "Notes to Consolidated Financial Statements" in "Item 8. Financial Statements and Supplementary Data". We have other accounting policies that we consider to be significant; however, these policies do not meet the definition of critical accounting estimates, because they generally do not require us to make estimates or judgments that are particularly difficult or subjective.

Regulatory Accounting

Our accounting policies historically reflect the effects of the rate-making process in accordance with Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. Our regulated segment continues to be cost-of-service rate regulated, and we believe the application of Statement No. 71 to that segment continues to be appropriate. We must reaffirm this conclusion at each balance sheet date. If, as a result of a change in circumstances, it is determined that the regulated segment no longer meets the criteria of regulatory accounting under Statement No. 71, that segment will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of Statement No. 71 results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the Kentucky Public Service Commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base this conclusion on certain factors, including changes in the regulatory environment, recent rate orders issued by regulatory agencies and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred or for probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our consolidated financial statements. We believe it is probable that we will recover the regulatory assets that have been recorded.

Pension

Our reported costs of providing pension benefits (as described in Note 5(a) of the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs associated with our defined benefit pension plan, for example, are impacted by employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plan and earnings on plan assets. Changes made to the provisions of the plan may impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

Changes in pension obligations associated with the above factors may not be immediately recognized as pension costs on the Consolidated Statements of Income, but may be deferred and amortized in the future over the average remaining service period of active plan participants. For the years ended June 30, 2008, 2007 and 2006, we recorded pension costs for our defined benefit pension plan of $670,000, $567,000 and $717,000, respectively.

Our pension plan assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting our discount rate assumption we considered rates of return on high-quality fixed-income investments that are expected to be available through the maturity dates of the pension benefits. Our expected long-term rate of return on pension plan assets was 7% for 2008 and was based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments. Our target investment allocation for equity investments includes allocations to domestic, international, and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We calculate the expected return on assets in our determination of pension costs based on the market value of assets at the measurement date. Using the market value recognizes investment gains or losses in the year in which they occur.

Based on an assumed long-term rate of return of 7%, discount rate of 6.5%, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plan will decrease from $670,000 in 2008 to $608,000 in 2009. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2009 by approximately $36,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $41,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $43,000.

Effective May 9, 2008, any employees hired on and after that date are not eligible to participate in our defined benefit pension plan. Employees hired after May 9, 2008 will receive a 4% employer contribution into their Employee Savings Plan account. This contribution is discretionary and subject to change with approval from our Board of Directors. Freezing the plan to new entrants did not impact the level of benefits for existing participants.

Effective July 1, 2008, we adopted the measurement date provision of Financial Accounting Standards Board Statement No. 158 entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which will require us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are expected to be $760,000. Of this amount, $152,000 is attributable to the change in measurement dates and will be charged directly to retained earnings on July 1, 2008. Thus, in fiscal 2009, pension costs in the amount of $608,000 are expected to be recognized in the Consolidated Statement of Income.

Provisions for Doubtful Accounts

We encounter risks associated with the collection of our accounts receivable. As such, we record a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, we primarily utilize our historical experience related to accounts written-off. Quarterly, at a minimum, we review the reserve for reasonableness based on the level of revenue and the aging of the receivable balance. The underlying assumptions used for the allowance can change from period to period and the allowance could potentially cause a material impact to the Consolidated Statements of Income and working capital. The actual weather, commodity prices and other internal and external economic conditions, such as the mix of the customer base between residential, commercial and industrial, may vary significantly from our assumptions and may impact operating income.

Unbilled Revenues and Gas Costs

At each month-end, we estimate the gas service that has been rendered from the date the customer's meter was last read to month-end. This estimate of unbilled usage is based on projected base load usage for each day unbilled plus projected weather-sensitive usage for each degree day during the unbilled period. Unbilled revenues and gas costs are calculated from the estimate of unbilled usage multiplied by the rates in effect at month-end. Actual usage patterns may vary from these assumptions and may impact operating income.

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to Federal regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations are recorded at the time the obligations are incurred. We do not recognize asset retirement obligations with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities are accreted for the change in their present value, through charges to depreciation, and the initial capitalized costs are depreciated over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the depreciation and accretion are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement date and the assumed credit-adjusted risk-free interest rate. Our asset retirement obligations are discussed in Note 3 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

Significant management judgment is generally required during the process of adopting new accounting pronouncements. See Note 2 of the Notes to Consolidated Financial Statements for a discussion of these pronouncements.

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as "estimates", "attempts", "expects", "monitors", "plans", "anticipates", "intends", "continues", "strives" ,"seeks", "will rely", "believes" and similar expressions.

These forward-looking statements include, but are not limited to, statements about:

- our operational plans,
- the cost and availability of our natural gas supplies,
- our capital expenditures,
- sources and availability of funding for our operations and expansion,
- our anticipated growth and growth opportunities through system expansion and acquisition,
- competitive conditions that we face,
- our production, storage, gathering and transportation activities,
- acquisition of service franchises from local governments,
- pension fund costs and management,
- our contractual obligations and cash requirements,
- management of our gas supply and risks due to potential fluctuation in the price of natural gas,
- our revenues, income, margins and profitability,
- our efforts to purchase and transport locally produced natural gas,
- recovery of regulatory assets,
- regulatory and legislative matters, and
- dividends.

Our forward-looking statements are not guarantees of future performance and are based upon currently available competitive, financial and economic data along with our operating plans.

Factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results include the impact or outcome of:

- the ongoing restructuring of the natural gas industry and the outcome of the regulatory proceedings related to that restructuring,
- general changes in the regulatory environment,
- a change in the rights under present regulatory rules to recover for costs of gas supply, other expenses and investments in capital assets,
- uncertainty of our capital expenditure requirements,
- changes in economic conditions, demographic patterns and weather conditions in our retail service areas,
- changes affecting our costs of providing gas service, including changes in gas supply costs, interest rates, the availability of external sources of financing for our operations, tax laws, environmental laws and the general rate of inflation,
- conservation by customers and loss of customers due to higher gas prices,
- changes affecting the costs of competing energy alternatives and competing gas distributors,
- changes in accounting principles and tax laws or the application of such principles and laws to us, and
- other matters described in Item 1A. Risk Factors.

Results of Operations

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented in the Consolidated Statements of Income is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the last two fiscal years compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

($000)	**2008 compared to 2007**	2007 compared to 2006
Increase (decrease) in regulated gross margins		
Gas sales	**1,349**	333
On-system transportation	**203**	(112)
Off-system transportation	**884**	436
Other	**(324)**	(155)
Total	**2,112**	502
Increase in non-regulated gross margins		
Gas sales	**1,441**	615
Other	**114**	16
Total	**1,555**	631
Increase in consolidated gross margins	**3,667**	1,133
Percentage increase (decrease) in regulated volumes		
Gas sales	**(5.4)**	1.8
On-system transportation	**(3.6)**	(3.0)
Off-system transportation	**29.1**	11.2
Percentage increase in non-regulated gas sales volumes	**9.6**	11.9

Heating degree days were 96% of normal thirty year average temperatures for fiscal 2008, as compared with 95% and 92% of normal temperatures for 2007 and 2006, respectively. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

Gross margins increased $3,667,000 in 2008 due to an increase in regulated gross margins of $2,112,000 and an increase in non-regulated gross margins of $1,555,000.

The $2,112,000 (9%) increase in regulated gross margins is attributable to increased base rates which became effective October 20, 2007 and a 2,849,000 Mcf (29%) increase in regulated off-system volumes transported. The impact of the increased rates was partially offset by a 178,000 Mcf (5%) decrease in volumes sold attributable to customer conservation.

The $1,555,000 (16%) increase in non-regulated gross margins is primarily attributable to a 569,000 Mcf (19%) increase in off-system volumes sold.

Gross margins increased $1,133,000 (4%) in 2007 due to an increase in non-regulated gross margins of $631,000 and a $502,000 increase in regulated gross margins.

The $631,000 (7%) increase in non-regulated gross margins in 2007 is primarily attributable to a 523,000 Mcf (12%) increase in volumes sold.

The $502,000 (2%) increase in regulated gross margins in 2007, is primarily attributable to a 985,000 Mcf increase in off-system transportation volumes (11%) and the 3% colder weather in 2007. These increases were offset by a 2% decrease in the number of regulated customers.

Operations and Maintenance

The $1,544,000 (12%) increase in operations and maintenance expense is primarily attributable to increased uncollectible expense ($326,000), increased storage maintenance expense ($307,000), increased labor expense ($274,000), increased transportation expenses ($165,000) and increased maintenance of transmission and distribution mains ($133,000).

Depreciation and Amortization

The $527,000 (11%) decrease in depreciation and amortization is primarily due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decrease was partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

The $494,000 (12%) increase in depreciation and amortization for 2007 is primarily due to an increase in depreciable plant resulting from capital expenditures of $8,083,000 for the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Interest

The increase in other interest for 2008 of $139,000 (25%) was a result of increased borrowings on our bank line of credit.

The decrease in other interest for 2007 of $169,000 (23%) was a result of decreased borrowings on our bank line of credit.

Income Tax Expense

The $990,000 (31%) increase in income tax expense for 2008 was attributable to the increase in net income before income taxes in 2008. Net income before income taxes increased due to the factors discussed throughout the "Results of Operations".

Basic and Diluted Earnings Per Common Share

For the fiscal years ended June 30, 2008, 2007 and 2006, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balance on our bank line of credit was $6,829,000 and $4,190,000 on June 30, 2008 and 2007, respectively. The weighted average interest rate on our bank line of credit was 3.2% and 6.3% as of June 30, 2008 and 2007, respectively. Based on the amount of our outstanding bank line of credit on June 30, 2008 and 2007, a 1% (one hundred basis points) increase in our average interest rate would result in a decrease in our annual pre-tax net income of $68,000 and $42,000, respectively.

Item 8. Financial Statements and Supplementary Data

Schedules other than those listed above are omitted because they are not required, are not applicable or the required information is shown in the financial statements or notes thereto.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's ("SEC") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a – 15(e) and 15d – 15(e) under the Exchange Act) as of June 30, 2008 and based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the time frame specified by the SEC's rules and forms.

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of June 30, 2008 based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on that evaluation, management concluded that our internal control over financial reporting was effective as of June 30, 2008.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended June 30, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting. That report immediately follows:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Delta Natural Gas Company, Inc.:

We have audited the internal control over financial reporting of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Certification of the Chief Executive Officer and Certification of the Chief Financial Officer. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended June 30, 2008 of the Company and our report dated August 28, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule, and included explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement 109* and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.*

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance of the Registrant

We have a Business Code of Conduct and Ethics that applies to all directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. You can find our Business Code of Conduct and Ethics on our website by going to the following address: http://www.deltagas.com. We will post any amendments to the Business Code of Conduct and Ethics, as well as any waivers that are required to be disclosed by the rules of either the Securities and Exchange Commission or the NASDAQ OMX Group, on our website.

Our Board of Directors has adopted charters for the Audit, Corporate Governance and Compensation and Executive Committees of the Board of Directors. You can find these documents on our website by going to the following address: http://www.deltagas.com and clicking on the appropriate link.

You can also obtain a printed copy of any of the materials referred to above by contacting us at the following address:

Delta Natural Gas Company, Inc.
Attn: John B. Brown
3617 Lexington Road
Winchester, KY 40391
(859) 744-6171

The Audit Committee of our Board of Directors is an "audit committee" for purposes of Section 3(a)(58) of the Securities Exchange Act of 1934.

The other information required by this Item is incorporated herein by reference to the applicable information in the proxy statement for our 2008 annual meeting.

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 14. Principal Accountant Fees and Services

Registrant intends to file a definitive proxy statement with the Commission pursuant to Regulation 14A (17 CFR 240.14a) no later than 120 days after the close of the fiscal year. In accordance with General Instruction G(3) to Form 10-K, the information called for by Items 10 (except for the language above in Item 10 in this report), 11, 12, 13 and 14 is incorporated herein by reference to the definitive proxy statement. The Report on Executive Compensation included in the Company's definitive proxy statement shall not be deemed incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements
See Index at Item 8

(2) Financial Statement Schedules
See Index at Item 8

(3) Exhibits

Exhibit No.

3(i) Registrant's Amended and Restated Articles of Incorporation (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(i) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.

3(ii) Registrant's Amended and Restated By-Laws (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(ii) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.

4(a) The Indenture dated March 1, 2006 in respect of 5.75% Insured Quarterly Notes due April 1, 2021, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-3 (Reg. No. 333-132322) dated March 31, 2006.

4(b) The Indenture dated January 1, 2003 in respect of 7% Debentures due February 1, 2023, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-2 (Reg. 333-100852) dated October 30, 2002.

10(a) Employment agreements between Registrant and four officers, those being John B. Brown, Johnny L. Caudill, Alan L. Heath and Glenn R. Jennings, are incorporated herein by reference to Exhibit 10(k) to Registrant's Form 10-Q (File No. 000-08788) for the period ended March 31, 2000.

10(b) Supplemental retirement benefit agreement and trust agreement between Registrant and Glenn R. Jennings is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated February 25, 2005.

10(c) Gas Sales Agreement, dated May 1, 2005, by and between the Registrant and Atmos Energy Marketing, L.L.C is filed herewith.

10(d) Gas Sales Agreement, dated May 1, 2003, by and between the Registrant and Atmos Energy Marketing, LLC is filed herewith.

10(e) Gas Transportation Agreement (Service Package 9069), dated December 19, 1994, by and between Tennessee Gas Pipeline Company and Registrant is incorporated herein by reference to Exhibit 10(e) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(f) GTS Service Agreement (Service Agreement No. 37815), dated November 1, 1993, by and between Columbia Gas Transmission Corporation and Registrant is incorporated herein by reference to Exhibit 10(f) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(g) FTS1 Service Agreement (Service Agreement No. 4328), dated October 4, 1994, by and between Columbia Gulf Transmission Company and Registrant is incorporated herein by reference to Exhibit 10(g) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003

10(h) Loan Agreement, dated October 31, 2002, by and between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(i) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(i) Promissory Note, in the original principal amount of $40,000,000, made by Registrant to the order of Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2002.

10(j) Gas Storage Lease, dated October 4, 1995, by and between Judy L. Fuson, Guardian of Jamie Nicole Fuson, a minor, and Lonnie D. Ferrin and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant is incorporated herein by reference to Exhibit 10(j) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(k) Gas Storage Lease, dated November 6, 1995, by and between Thomas J. Carnes, individually and as Attorney-in-fact and Trustee for the individuals named therein, and Registrant, is incorporated herein by reference to Exhibit 10(k) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003

10(l) Deed and Perpetual Gas Storage Easement, dated December 21, 1995, by and between Katherine M. Cornelius, William Cornelius, Frances Carolyn Fitzpatrick, Isabelle Fitzpatrick Smith and Kenneth W. Smith and Registrant is incorporated herein by reference to Exhibit 10(l) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(m) Underground Gas Storage Lease and Agreement, dated March 9, 1994, by and between Equitable Resources Exploration, a division of Equitable Resources Energy Company, and Lonnie D. Ferrin and Amendment No. 1 and Novation to Underground Gas Storage Lease and Agreement, dated March 22, 1995, by and between Equitable Resources Exploration, Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(m) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(n) Base Contract for Short-Term Sale and Purchase of Natural Gas, dated January 1, 2002, by and between M & B Gas Services, Inc. and Registrant, is incorporated herein by reference to Exhibit 10(n) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(o) Oil and Gas Lease, dated July 19, 1995, by and between Meredith J. Evans and Helen Evans and Paddock Oil and Gas, Inc.; Assignment, dated June 15, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; Assignment, dated August 31, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(o) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(p) Agreement to transport natural gas between Registrant and Nami Resources Company L.L.C. is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated March 23, 2005.

10(q) Modification Agreement extending to October 31, 2009 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2007.

12 Computation of the Consolidated Ratio of Earnings to Fixed Charges.

21 Subsidiaries of the Registrant.

23 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 29th day of August, 2008.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 29, 2008

(ii) Principal Financial Officer and Principal Accounting Officer

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 29, 2008

(iii) A Majority of the Board of Directors:

/s/Linda K. Breathitt (Linda K. Breathitt)	Director	August 29, 2008
/s/Lanny D. Greer (Lanny D. Greer)	Director	August 29, 2008
/s/Billy Joe Hall (Billy Joe Hall)	Director	August 29, 2008
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 29, 2008
/s/Lewis N. Melton (Lewis N. Melton)	Director	August 29, 2008
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 29, 2008
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 29, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Delta Natural Gas Company, Inc.:

We have audited the accompanying consolidated balance sheets of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended June 30, 2008. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at June 30, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on July 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement 109*.

As discussed in Note 2 to the consolidated financial statements, on June 30, 2007, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated August 28, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Years Ended June 30,	2008	2007	2006
Operating Revenues	**$ 112,657,117**	$ 98,168,391	$ 117,247,144
Operating Expenses			
Purchased gas	**$ 76,882,387**	$ 66,060,368	$ 86,271,854
Operation and maintenance	**14,128,620**	12,584,607	12,293,652
Depreciation and amortization	**4,171,145**	4,697,639	4,203,711
Taxes other than income taxes	**1,811,229**	1,857,734	1,720,420
Total operating expenses	**$ 96,993,381**	$ 85,200,348	$ 104,489,637
Operating Income	**$ 15,663,736**	$ 12,968,043	$ 12,757,507
Other Income and Deductions, Net	**$ 83,521**	$ 134,265	$ 227,636
Interest Charges			
Interest on long-term debt	**$ 3,677,983**	$ 3,694,389	$ 3,968,993
Other interest	**705,240**	565,790	735,082
Amortization of debt expense	**387,266**	387,082	273,533
Total interest charges	**$ 4,770,489**	$ 4,647,261	$ 4,977,608
Income Before Income Taxes	**$ 10,976,768**	$ 8,455,047	$ 8,007,535
Income Tax Expense	**$ 4,146,900**	$ 3,156,700	$ 2,982,900
Net Income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635
Basic and Diluted Earnings Per Common Share	**$ 2.08**	$ 1.62	$ 1.55
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,285,464**	3,265,800	3,242,223
Dividends Declared Per Common Share	**$ 1.24**	$ 1.22	$ 1.20

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows

For the Years Ended June 30,	2008	2007	2006
Cash Flows From Operating Activities			
Net income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	**4,660,410**	5,157,922	4,550,444
Deferred income taxes and investment tax credits	**2,095,000**	2,345,300	1,814,475
Gain on sale of asset	**(16,955)**	—	—
Other - net	**(219,041)**	(205,827)	(73,869)
(Increase) decrease in assets			
Accounts receivable	**(5,016,055)**	1,746,732	(1,374,334)
Gas in storage	**(2,634,602)**	(475,801)	(2,172,326)
Deferred gas cost	**(1,670,877)**	(1,116,773)	819,453
Materials and supplies	**(38,568)**	(87,859)	103,365
Prepayments	**(129,153)**	(897,682)	(525,634)
Other assets	**(75,390)**	(197,887)	(772,733)
Increase (decrease) in liabilities			
Accounts payable	**1,920,832**	3,835,813	(668,039)
Accrued taxes	**890,309**	(1,061,563)	(226,523)
Other current liabilities	**(889)**	148,901	(66,759)
Other liabilities	**(2,358)**	(3,717)	(9,107)
Net cash provided by operating activities	**$ 6,592,531**	$ 14,485,906	$ 6,423,048
Cash Flows From Investing Activities			
Capital expenditures	**$ (5,563,667)**	$ (8,082,918)	$ (7,781,396)
Proceeds from sale of property, plant and equipment	**297,425**	146,810	204,372
Net cash used in investing activities	**$ (5,266,242)**	$ (7,936,108)	$ (7,577,024)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows (continued)

For the Years Ended June 30,	**2008**	2007	2006
Cash Flows From Financing Activities			
Dividends on common stock	**$ (4,073,278)**	$ (3,983,909)	$ (3,890,800)
Issuance of common stock, net	**477,155**	504,309	676,435
Long-term debt issuance expense	—	(10,970)	(2,329,393)
Issuance of long-term debt	—	—	40,000,000
Repayment of long-term debt	**(307,000)**	(165,000)	(34,367,000)
Issuance of notes payable	**64,602,956**	51,518,605	92,710,796
Repayment of notes payable	**(61,964,083)**	(54,375,121)	(91,623,484)
Net cash (used in) provided by financing activities	**$ (1,264,250)**	$ (6,512,086)	$ 1,176,554
Net Increase in Cash and Cash Equivalents	**$ 62,039**	$ 37,712	$ 22,578
Cash and Cash Equivalents, Beginning of Year	**187,820**	150,108	127,530
Cash and Cash Equivalents, End of Year	**$ 249,859**	$ 187,820	$ 150,108
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	**$ 4,383,367**	$ 4,232,155	$ 4,766,191
Income taxes (net of refunds)	**1,376,093**	1,763,518	1,922,348

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets

As of June 30,		2008		2007
Assets				
Current Assets				
Cash and cash equivalents	$	**249,859**	$	187,820
Accounts receivable, less provisions for doubtful accounts of $465,000 and $300,000 in 2008 and 2007, respectively		**11,437,219**		7,389,993
Gas in storage, at average cost		**14,476,393**		11,841,791
Deferred gas costs (Notes 1 and 13)		**4,612,752**		2,941,826
Materials and supplies, at average cost		**565,333**		559,087
Prepayments		**2,683,854**		2,629,682
Total current assets	$	**34,025,410**	$	25,550,199
Property, Plant and Equipment	$	**192,127,184**	$	187,148,032
Less – Accumulated provision for depreciation		**(67,754,068)**		(64,879,205)
Net property, plant and equipment	$	**124,373,116**	$	122,268,827
Other Assets				
Cash surrender value of officers' life insurance (face amount of $1,146,786)	$	**444,312**	$	425,609
Prepaid pension cost (Note 5)		**1,423,932**		951,571
Regulatory assets (Note 1)		**7,713,358**		8,220,590
Unamortized debt expense and other (Notes 1 and 9)		**2,834,728**		2,984,154
Total other assets	$	**12,416,330**	$	12,581,924
Total assets	$	**170,814,856**	$	160,400,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Balance Sheets (continued)

As of June 30,		**2008**		2007
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable	$	**12,154,432**	$	10,299,066
Notes payable (Note 8)		**6,828,791**		4,189,918
Current portion of long-term debt (Notes 9 and 10)		**1,200,000**		1,200,000
Accrued taxes		**1,656,391**		973,651
Customers' deposits		**505,058**		482,446
Accrued interest on debt		**865,727**		865,871
Accrued vacation		**720,625**		702,521
Deferred income taxes		**1,483,700**		1,273,000
Other liabilities		**418,239**		459,651
Total current liabilities	**$**	**25,832,963**	$	20,446,124
Long-term debt (Notes 9 and 10)	**$**	**58,318,000**	$	58,625,000
Deferred Credits and Other				
Deferred income taxes	**$**	**24,576,000**	$	22,467,900
Investment tax credits		**177,800**		213,600
Regulatory liabilities (Note 1)		**2,144,951**		2,503,256
Asset retirement obligations and other (Note 3)		**2,171,557**		1,716,599
Total deferred credits and other	**$**	**29,070,308**	$	26,901,355
Commitments and Contingencies (Note 12)				
Total liabilities	**$**	**113,221,271**	$	105,972,479
Common Shareholders' Equity				
Common shares ($1.00 par value), 20,000,000 shares authorized; 3,295,759 and 3,277,106 shares outstanding at June 30, 2008 and June 30, 2007, respectively	**$**	**3,295,759**	$	3,277,106
Premium on common shares		**43,967,481**		43,508,979
Retained earnings		**10,330,345**		7,642,386
Total common shareholders' equity	**$**	**57,593,585**	$	54,428,471
Total liabilities and common shareholders' equity	**$**	**170,814,856**	$	160,400,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Changes in Shareholders' Equity

For the Years Ended June 30,	2008	2007	2006
Common Shares			
Balance, beginning of year	$ 3,277,106	$ 3,256,043	$ 3,229,988
Dividend reinvestment and stock purchase plan, $1.00 par value of 18,653, 21,063 and 26,055 shares issued in 2008, 2007 and 2006, respectively	18,653	21,063	26,055
Balance, end of year	$ 3,295,759	$ 3,277,106	$ 3,256,043
Premium on Common Shares			
Balance, beginning of year	$ 43,508,979	$ 43,025,733	$ 42,375,353
Dividend reinvestment and stock purchase plan	458,502	483,246	650,380
Balance, end of year	$ 43,967,481	$ 43,508,979	$ 43,025,733
Retained Earnings			
Balance, beginning of year	$ 7,642,386	$ 6,327,948	$ 5,194,113
Adoption of FASB Interpretation No. 48	(68,631)	—	—
Balance, beginning of year, as adjusted	$ 7,573,755	$ 6,327,948	$ 5,194,113
Net income	6,829,868	5,298,347	5,024,635
Cash dividends declared on common shares (See Consolidated Statements of Income for rates)	(4,073,278)	(3,983,909)	(3,890,800)
Balance, end of year	$ 10,330,345	$ 7,642,386	$ 6,327,948
Common Shareholders' Equity			
Balance, beginning of year	$ 54,428,471	$ 52,609,724	$ 50,799,454
Adoption of FASB Interpretation No. 48	(68,631)	—	—
Balance, beginning of year, as adjusted	$ 54,359,840	$ 52,609,724	$ 50,799,454
Net income	6,829,868	5,298,347	5,024,635
Issuance of common stock	477,155	504,309	676,435
Dividends on common stock	(4,073,278)	(3,983,909)	(3,890,800)
Balance, end of year	$ 57,593,585	$ 54,428,471	$ 52,609,724

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Principles of Consolidation Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(b) Cash Equivalents For the purposes of the Consolidated Statements of Cash Flows, all temporary cash investments with a maturity of three months or less at the date of purchase are considered cash equivalents.

(c) Property, Plant and Equipment Property, plant and equipment is stated at original cost, which includes materials, labor, labor related costs and an allocation of general and administrative costs. Construction work in progress has been included in the rate base for determining customer rates, and therefore an allowance for funds used during construction has not been recorded. The cost of regulated plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense, less salvage value, is charged to the accumulated provision for depreciation.

(d) Depreciation We determine the provision for depreciation using the straight-line method and by the application of rates to various classes of utility plant. The rates are based upon the estimated service lives of the properties and were equivalent to composite rates of 2.3%, 2.7% and 2.5% of average depreciable plant for 2008, 2007 and 2006, respectively.

(e) Maintenance All expenditures for maintenance and repairs of units of property are charged to the appropriate maintenance expense accounts in the month incurred. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired.

(f) Gas Cost Recovery We have a Gas Cost Recovery ("GCR") clause which provides for a dollar-tracker that matches revenues and gas costs and provides eventual dollar-for-dollar recovery of all gas costs incurred by the regulated segment and approved by the Kentucky Public Service Commission. We expense gas costs based on the amount of gas costs recovered through revenue. Any differences between actual gas costs and those estimated costs billed are deferred and reflected in the computation of future billings to customers using the GCR mechanism.

(g) Revenue Recognition We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	**2008**	2007
Unbilled revenues ($)	**1,579**	1,058
Unbilled gas costs ($)	**736**	497
Unbilled volumes (Mcf)	**51**	48

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(h) Excise Taxes Certain excise taxes levied by state or local governments are collected by Delta from our customers. These taxes are accounted for on a net basis and therefore are not included as revenues in the accompanying Consolidated Statements of Income.

(i) Revenues and Customer Receivables We serve 38,000 customers in central and southeastern Kentucky. Revenues and customer receivables arise primarily from sales of natural gas to customers and from transportation services for others. Provisions for doubtful accounts are recorded to reflect the expected net realizable value of accounts receivable. Customer accounts are charged off when deemed to be uncollectible or when turned over to a collection agency to pursue.

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

(k) Rate Regulated Basis of Accounting Our regulated operations follow the accounting and reporting requirements of Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. The economic effects of regulation can result in a regulated company recovering costs from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets in the Consolidated Balance Sheets (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities). The amounts recorded as regulatory assets and regulatory liabilities are as follows:

($000)	2008	2007
Regulatory assets		
Current assets		
Deferred gas costs	**4,613**	2,942
Other assets		
Loss on extinguishment of debt	**2,539**	2,729
Asset retirement obligations	**1,352**	1,249
Accrued pension	**3,538**	3,935
Regulatory case expenses	**285**	307
Total other assets	**7,714**	8,220
Total regulatory assets	**12,327**	11,162
Regulatory liabilities		
Accrued cost of removal on long-lived assets	**615**	785
Regulatory liability for deferred income taxes	**1,530**	1,718
Total regulatory liabilities	**2,145**	2,503

Deferred gas costs are presented every three months to the Kentucky Public Service Commission for recovery in accordance with the gas cost recovery rate mechanism. We are currently earning a return on loss on extinguishment of debt. Asset retirement costs are recovered through customer rates as they are included in our depreciation rates. Pension expenses and rate case expenses are recovered through customer rates as allowed operating expenses.

(l) Impairment of Long-Lived Assets We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. In the opinion of management, our long-lived assets are appropriately valued in the accompanying consolidated financial statements.

(m) Derivatives We purchase and sell natural gas. Certain of our gas purchase and sale contracts qualify as a derivative under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. All such contracts have been designated as normal purchases and sales and as such are accounted for under the accrual basis and are not recorded at fair value in the accompanying consolidated financial statements.

(2) New Accounting Pronouncements

Recently Adopted Pronouncements

In July, 2006, the FASB issued Interpretation No. 48, entitled Accounting for Uncertainty in Income Taxes, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Financial Accounting Standards Board Statement No. 109, entitled Accounting for Income Taxes. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

We adopted the provisions of Interpretation No. 48 on July 1, 2007. The adoption of Interpretation No. 48 resulted in an adjustment to beginning retained earnings of $68,000. At adoption, the total amount of gross unrecognized tax benefits for uncertain tax positions, including positions impacting only the timing of tax benefits, was $668,000, of which $97,000 related to interest. Note 4 of the Notes to Consolidated Financial Statements further discusses our income taxes.

We have not entered into any share-based payment transactions, therefore, the adoption of Statement of Financial Accounting Standards No. 123(R), entitled Share-Based Payment, and Securities and Exchange Commission Staff Accounting Bulletin No. 107, entitled Share-Based Payment, had no impact on us.

In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 requires employers who sponsor defined benefit plans to recognize the funded status of the plan and gains and losses not previously recognized in net periodic benefit cost in the sponsor's financial statements in fiscal years ending after December 15, 2006. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Statement No. 71 provides guidance to regulated utilities for deferring costs that would otherwise be charged to expense or equity by non-regulated enterprises. We adopted the disclosure and recognition provisions of Statement No. 158 effective June 30, 2007 and in applying the provisions of this statement, we recorded a regulatory asset representing the adjustment to the pension asset in recognizing the funded status of the plan. This adjustment would have been represented in Accumulated Other Comprehensive Income without the application of Statement No. 71. The adoption of Statement No. 158 recognition and disclosure provisions resulted in an increase in regulatory assets of $3,935,000 offset by a decrease in prepaid pension cost of $3,935,000. The adoption of Statement No. 158, as further discussed in Note 5 of the Notes to Consolidated Financial Statements, did not have any impact on our consolidated results of operations or cash flows.

Effective July 1, 2008, we will adopt the measurement date provision of Statement No. 158, which will require us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are expected to be $760,000. Of this amount, $152,000 is attributable to the change in measurement dates and will be charged directly to retained earnings on July 1, 2008. In fiscal 2009, pension costs in the amount of $608,000 are expected to be recognized in the Consolidated Statement of Income.

Recently Issued Pronouncements

In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. Both statements are effective for fiscal years beginning after November 15, 2007. The statements define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. We do not expect these statements, which shall be effective for our 2009 fiscal year, to have a material impact on our results of operations or financial position.

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of FASB Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We do not expect this statement, which shall be effective for our 2010 fiscal year, to have an impact on our results of operations or financial position.

(3) Asset Retirement Obligations

Legal obligations

As required by Financial Accounting Standards Board Statement No. 143, entitled Accounting for Asset Retirement Obligations, and Financial Accounting Standards Interpretation No. 47, entitled Accounting for Conditional Asset Retirement Obligations, as of June 30, 2008 and 2007 we have accrued liabilities and related assets, net of accumulated depreciation, relative to the legal obligation to retire certain gas wells, storage tanks, mains and services. For asset retirement obligations related to regulated assets, accretion of the liability and depreciation of the asset retirement costs are recorded as regulatory assets, pursuant to Statement No. 71, as we recover the cost of removing our regulated assets through our depreciation rates.

The following is a summary of our asset retirement obligations and related assets (net of accumulated depreciation), reflected in the accompanying Consolidated Balance Sheets under the captions asset retirement obligations and other, and property, plant and equipment, respectively:

($000)	Asset Retirement Obligations	Net Assets
As of June 30, 2006	1,578	274
Accretion	120	—
Depreciation	—	(10)
Change in obligations	(232)	(232)
As of June 30, 2007	1,466	32
Accretion	111	—
Depreciation	—	(2)
Change in obligations	23	23
As of June 30, 2008	1,600	53

We have an additional asset retirement obligation relative to the retirement of wells located at our underground natural gas storage facility. Since we expect to utilize the storage facility as long as we provide natural gas to our customers, we have determined the underlying asset has an indeterminate life.

Therefore, we have not recorded a liability associated with the cost to retire the asset, pursuant to Interpretation No. 47.

Non-legal obligations

In accordance with established regulatory practices, we accrue costs of removal on long-lived assets through depreciation expense if we believe removal of the assets at the end of their useful life is likely even though such costs do not represent legal obligations under Statement No. 143. In accordance with the provisions of Statement No. 71, we have recorded approximately $615,000 and $785,000 of such accrued cost of removal as regulatory liabilities on the accompanying Consolidated Balance Sheets as of June 30, 2008 and 2007, respectively.

(4) Income Taxes

We provide for income taxes on temporary differences resulting from the use of alternative methods of income and expense recognition for financial and tax reporting purposes. The differences result primarily from the use of accelerated tax depreciation methods for certain properties versus the straight-line depreciation method for financial reporting purposes, differences in recognition of purchased gas costs and certain accruals which are not currently deductible for income tax purposes. Investment tax credits were deferred for certain periods prior to fiscal 1987 and are being amortized to income over the estimated useful lives of the applicable properties. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The current portion of net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in deferred credits and other on the accompanying Consolidated Balance Sheets. The temporary differences which gave rise to the net accumulated deferred income tax liability for the periods are as follows:

($000)	**2008**	2007
Deferred Tax Liabilities		
Accelerated depreciation	**23,251**	21,036
Deferred gas costs	**1,751**	1,116
Pension	**515**	921
Regulatory assets – loss on extinguishment of debt	**964**	1,036
Regulatory assets – asset retirement obligations	**513**	474
Regulatory assets – unrecognized accrued pension	**1,343**	1,494
Other	**445**	448
Total	**28,782**	26,525
Deferred Tax Assets		
Alternative minimum tax credits	**172**	753
Regulatory liabilities	**815**	950
Investment tax credits	**68**	81
Reserve for bad debt	**177**	114
Asset retirement obligations	**545**	494
Accrued personal leave	**227**	215
Section 263(a) capitalized costs	**113**	82
Other	**605**	95
Total	**2,722**	2,784
Net accumulated deferred income tax liability	**26,060**	23,741

The components of the income tax provision are comprised of the following for the years ended June 30:

($000)	**2008**	2007	2006
Components of Income Tax Expense			
Current			
Federal	**1,158**	494	813
State	**395**	213	256
Total	**1,553**	707	1,069
Deferred	**2,594**	2,450	1,914
Income tax expense	**4,147**	3,157	2,983

Reconciliation of the statutory federal income tax rate to the effective income tax rate is shown in the table below:

	2008	2007	2006
Statutory federal income tax rate	**34.0%**	34.0%	34.0%
State income taxes, net of federal benefit	**4.0**	4.6	4.6
Amortization of investment tax credits	**(0.3)**	(0.5)	(0.5)
Other differences, net	—	(0.8)	(0.8)
Effective income tax rate	**37.7%**	37.3%	37.3%

In July 2006, the Financial Accounting Standards Board issued Interpretation No. 48, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Statement No. 109. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

The liability for unrecognized tax benefits expected to be recognized within the next twelve months has been presented in accrued taxes in the June 30, 2008 Consolidated Balance Sheet. The liability for unrecognized tax benefits not expected to be recognized within the next twelve months has been presented in asset retirement obligations and other in the June 30, 2008 Consolidated Balance Sheet. Interest and penalties on tax uncertainties are classified in income tax expense on the Consolidated Statements of Income.

The amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $156,000. We accrued interest of $116,000 on unrecognized tax positions, of which $18,000 was recognized on the 2008 Consolidated Statement of Income. We expect our unrecognized tax benefits to decrease approximately $204,000 within the next twelve months, primarily due to filing a method change with the Internal Revenue Service. This decrease is related to timing differences and is not expected to have a material impact on our financial position, results of operations or effective tax rate. It is reasonably possible that there will be additional changes to the unrecognized tax benefits. However, it is not expected that such change will have a significant impact on our results of operations or financial position.

The following is a tabular reconciliation of our unrecognized tax benefits:

($000)	
As of July 1, 2007	668
Gross increases	
Tax positions in prior period	1
Tax positions in current period	102
Gross decreases	
Tax positions in prior period	(102)
Lapse of statute of limitations	(16)
As of June 30, 2008	653

We file income tax returns in the federal and Kentucky jurisdictions. Tax years previous to June 30, 2005 and June 30, 2004 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(5) Employee Benefit Plans

(a) Defined Benefit Retirement Plan We have a trusteed, noncontributory, defined benefit pension plan covering all eligible employees. Retirement income is based on the number of years of service and annual rates of compensation. The Company makes annual contributions equal to the amounts necessary to fund the plan adequately.

We adopted the disclosure and recognition provisions of Statement No. 158 effective June 30, 2007. The following table describes the total incremental effect of the adoption of Statement No. 158 on individual line items on the June 30, 2007 Consolidated Balance Sheet. This statement requires employers who sponsor defined benefit plans to recognize the funded status of a defined benefit pension plan on the statement of financial position and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. Statement No. 71 provides that regulated entities can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on Financial Accounting Standards Board Statement No. 87, entitled Employers' Accounting for Pensions, which was amended by Statement No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery; therefore, we have recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the defined benefit plan that is expected to be recovered through future rates. The regulatory asset will be adjusted annually as prior service cost and actuarial losses are recognized in net periodic benefit cost.

($000)	Before application of Statement No. 158	Adjustments	After application of Statement No. 158
Prepaid pension cost	4,887	(3,935)	952
Regulatory assets – accrued pension	—	3,935	3,935

Our obligations and the funded status of our plan, measured at March 31, are as follows:

($000)	**2008**	2007
Change in Benefit Obligation		
Benefit obligation at beginning of year	**13,277**	12,696
Service cost	**749**	715
Interest cost	**746**	700
Actuarial (gain) loss	**(894)**	202
Amendment	**(3)**	—
Benefits paid	**(1,102)**	(1,036)
Benefit obligation at end of year	**12,773**	13,277
Change in Plan Assets		
Fair value of plan assets at beginning of year	**14,229**	13,067
Actual return on plan assets	**325**	698
Employer contributions	**745**	1,500
Benefits paid	**(1,102)**	(1,036)
Fair value of plan assets at end of year	**14,197**	14,229
Recognized Amounts		
Projected benefit obligation	**(12,773)**	(13,277)
Plan assets at fair value	**14,197**	14,229
Funded status	**1,424**	952
Net amount recognized as prepaid benefit costs in the Consolidated Balance Sheets	**1,424**	952
Items Not Yet Recognized as a Component of Net Periodic Benefit Costs		
Prior service cost	**(857)**	(940)
Net loss	**4,395**	4,875
Amounts recognized as regulatory assets	**3,538**	3,935

The accumulated benefit obligation was $11,679,000 and $12,191,000 for 2008 and 2007, respectively.

($000)	**2008**	2007	2006
Components of Net Periodic Benefit Cost			
Service cost	**749**	715	780
Interest cost	**745**	700	697
Expected return on plan assets	**(988)**	(995)	(931)
Amortization of unrecognized net loss	**250**	233	257
Amortization of prior service cost	**(86)**	(86)	(86)
Net periodic benefit cost	**670**	567	717
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	**6.5**	5.8	5.8
Rate of compensation increase	**4.0**	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	**5.8**	5.8	5.8
Expected long-term return on plan assets	**7.0**	8.0	8.0
Rate of compensation increase	**4.0**	4.0	4.0

Our expected long-term rate of return on pension plan assets is based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments and the market-related value of plan assets; market-related value of plan assets is based upon the fair value of the plan assets.

Plan Assets

Our pension plan weighted-average asset allocations as of the plan's measurement date (March 31) by asset category are as follows:

	2008	2007
Equity securities	**63%**	59%
Fixed income securities	**30**	37
Other	**7**	4
	100%	100%

Our equity investment target of approximately 65% includes allocations to domestic, international and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We expect to contribute $677,000 to the pension plan in 2009.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

($000)

2009	732
2010	334
2011	822
2012	549
2013	2,183
2014 – 2018	6,112

Effective May 9, 2008, any employees hired on and after that date are not eligible to participate in our defined benefit pension plan. Employees hired after May 9, 2008 will receive a 4% contribution into their Employee Savings Plan account. This contribution is discretionary and subject to change with approval from our Board of Directors. Freezing the defined benefit plan for new entrants did not impact the level of benefits for existing participants.

The Statement of Financial Accounting Standards No. 106, entitled Employers' Accounting for Postretirement Benefits, and the Statement of Financial Accounting Standards No. 112, entitled Employers' Accounting for Postemployment Benefits, do not affect us as we do not provide postretirement or postemployment benefits other than the pension plan for retired employees.

(b) Employee Savings Plan We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 3.5% of the employee's annual compensation. Employees hired after May 9, 2008 will annually receive a 4% non-elective contribution into their Savings Plan account beginning July 1, 2008. This contribution is discretionary and subject to change with approval from our Board of Directors. For 2008, 2007, and 2006, Delta's Savings Plan expense was $281,000, $256,000 and $240,000, respectively. Effective July 1, 2008, the Company will match 100% of the employee's elective contribution up to a maximum matching contribution of 4.0%.

(c) Supplemental Retirement Agreement We sponsor a nonqualified defined contribution supplemental retirement agreement for Glenn R. Jennings, Delta's Chairman of the Board, President and Chief Executive Officer. Delta contributes $60,000 annually into an irrevocable trust until Mr. Jennings' retirement. At retirement, the trustee will make annual payments of $100,000 to Mr. Jennings until the trust is depleted. As of June 30, 2008 and 2007, the irrevocable trust assets are $250,000 and $203,000, respectively. These amounts are included in unamortized debt expense and other on the accompanying Consolidated Balance Sheets. Liabilities, in corresponding amounts, are included in asset retirement obligations and other on the accompanying Consolidated Balance Sheets.

(6) Dividend Reinvestment and Stock Purchase Plan

Our Dividend Reinvestment and Stock Purchase Plan ("Reinvestment Plan") provides that shareholders of record can reinvest dividends and also make limited additional investments of up to $50,000 per year in shares of common stock of the Company. Under the Reinvestment Plan we issued 18,653, 21,063 and 26,055 shares in 2008, 2007 and 2006, respectively. We registered 200,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2008 there were 156,098 shares available for issuance.

(7) Note Receivable From Officer Related Party Transaction

Reflected in our 2007 and 2006 Consolidated Statements of Income is $62,000 and $24,000, respectively, of compensation related to the forgiveness of principal on a $160,000 loan made to Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer. We forgave $2,000 of the principal amount for each month of service Mr. Jennings completed through June 30, 2007. Mr. Jennings made monthly interest payments on the note based on an annual interest rate of 6%. We forgave the remaining balance of the note effective June 30, 2007.

(8) Notes Payable

The current available bank line of credit with Branch Banking and Trust Company is $40,000,000, of which $6,829,000 and $4,190,000 were borrowed having a weighted average interest rate of 3.21% and 6.32% as of June 30, 2008 and 2007, respectively. The maximum amount borrowed during 2008 and 2007 was $26,858,000 and $18,975,000, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The annual cost of the unused bank line of credit is .125% and the bank line of credit extends through October 31, 2009.

(9) Long-Term Debt

In April, 2006, we issued $40,000,000 of 5.75% Insured Quarterly Notes that mature in April, 2021. Redemption of up to $25,000 annually will be made on behalf of deceased holders, up to an aggregate of $800,000 annually for all deceased beneficial owners. The 5.75% Insured Quarterly Notes can be redeemed by us beginning in April, 2009 with no premium.

In February, 2003 we issued $20,000,000 of 7.00% Debentures that mature in February, 2023. Redemption of up to $25,000 annually will be made on behalf of individual deceased holders, up to an aggregate of $400,000 annually for all deceased beneficial owners. The 7.00% Debentures can be redeemed by us through February, 2009 at a 1% premium. Subsequent to February, 2009, there is no premium to redeem the Debentures.

In May, 2006, we redeemed $23,672,000 aggregate principal amount of 7.15% Debentures due 2018.

In May, 2006, we redeemed $10,169,000 aggregate principal amount of 6 5/8% Debentures due 2023.

We amortize debt issuance expenses over the life of the related debt on a straight-line basis, which approximates the effective yield method. At June 30, 2008 and 2007, the unamortized balance was $5,123,000 and $5,511,000, respectively. Loss on extinguishment of debt of $2,539,000 and $2,729,000 included in the above has been deferred and is being amortized over the term of the related debt consistent with regulatory treatment.

The current portion of long-term debt of $1,200,000 represents the maximum aggregate principal amounts which can be paid to deceased beneficial owners. Therefore, the maximum maturities over the next five years are $1,200,000 each year. The Insured Quarterly Notes and Debentures do not have any sinking fund requirements.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and

- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(10) Fair Values of Financial Instruments

The fair value of our long-term debt is estimated using discounted cash flow analysis, based on our current incremental borrowing rates for similar types of borrowing arrangements. The fair value of our long-term debt at June 30, 2008 and 2007 was estimated to be $55,164,000 and $57,457,000, respectively. The carrying amounts in the accompanying Consolidated Balance Sheets as of June 30, 2008 and 2007 are $59,518,000 and $59,825,000, respectively.

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value.

(11) Operating Leases

We have no non-cancellable operating leases. Our operating leases relate primarily to well and compressor station site leases and are cancellable at our option. Rental expense under operating leases was $78,000, $78,000 and $88,000 for the three years ending June 30, 2008, 2007 and 2006, respectively.

(12) Commitments and Contingencies

We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $3 million would be paid in addition to continuation of specified benefits for up to five years.

(13) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and our transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. The test year for the rate case was the twelve months ended December 31, 2006. The increased rates were requested to become effective May 20, 2007, but the implementation of the proposed rates was suspended until October 20, 2007.

During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, either our franchises have expired, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible.

Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

(14) Operating Segments

Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the sale or transportation of natural gas. Price risk for the regulated business is mitigated through our Gas Cost Recovery Clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided $17,087,000, $9,843,000 and $15,422,000 of non-regulated revenues during 2008, 2007 and 2006, respectively, although there is no assurance that revenues from them will continue at these levels.

In 2008, 2007 and 2006, we purchased approximately 99% of our natural gas from interstate sources. We utilize Atmos Energy Marketing and M & B Gas Services to fulfill our interstate purchase requirements.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenues and expenses are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment. Segment information is shown in the following table:

($000)	**2008**	2007	2006
Operating Revenues			
Regulated			
External customers	**58,219**	53,499	65,343
Intersegment	**4,019**	3,643	3,498
Total regulated	**62,238**	57,142	68,841
Non-regulated			
External customers	**54,438**	44,669	51,904
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)
Total operating revenues	**112,657**	98,168	117,247
Operating Expenses			
Regulated			
Purchased gas	**33,493**	30,887	43,233
Depreciation	**4,053**	4,579	4,084
Other	**14,840**	13,538	13,292
Total regulated	**52,386**	49,004	60,609
Non-regulated			
Purchased gas	**43,389**	35,173	43,039
Depreciation	**118**	119	120
Other	**5,119**	4,547	4,219
Total non-regulated	**48,626**	39,839	47,378
Eliminations for intersegment	**(4,019)**	(3,643)	(3,498)
Total operating expenses	**96,993**	85,200	104,489
Other Income and Deductions, Net			
Regulated	**83**	134	228
Non-regulated	**—**	—	—
Total other income and deductions	**83**	134	228
Interest Charges			
Regulated	**4,556**	4,501	4,991
Non-regulated	**214**	146	(13)
Total interest charges	**4,770**	4,647	4,978
Income Tax Expense			
Regulated	**2,022**	1,349	1,235
Non-regulated	**2,125**	1,808	1,748
Total income tax expense	**4,147**	3,157	2,983
Net Income			
Regulated	**3,356**	2,422	2,234
Non-regulated	**3,474**	2,876	2,791
Total net income	**6,830**	5,298	5,025
Assets			
Regulated	**163,952**	154,029	150,541
Non-regulated	**6,863**	6,372	5,013
Total assets	**170,815**	160,401	155,554
Capital Expenditures			
Regulated	**5,564**	8,083	7,781
Non-regulated	**—**	—	—
Total capital expenditures	**5,564**	8,083	7,781

(15) Subsequent Events

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits and promote conservation awareness, and it also provides rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

(16) Quarterly Financial Data (Unaudited)

The quarterly data reflects, in the opinion of management, all normal recurring adjustments necessary to present fairly the results for the interim periods.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2008				
September 30	**$ 12,404,170**	**$ (102,919)**	**$ (810,945)**	**$ (.25)**
December 31	**29,298,418**	**5,289,682**	**2,455,285**	**.75**
March 31	**48,396,125**	**9,884,436**	**5,421,108**	**1.65**
June 30	**22,558,404**	**592,537**	**(235,580)**	**(.07)**
Fiscal 2007				
September 30	$ 13,113,351	$ 274,217	$ (536,745)	$ (.16)
December 31	28,434,215	5,135,224	2,380,821	.73
March 31	41,022,436	7,140,820	3,665,329	1.12
June 30	15,598,389	417,782	(211,058)	(.07)

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED JUNE 30, 2008, 2007, and 2006

Column A	Column B	Column C Additions		Column D Deductions	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts – Recoveries	Amounts Charged Off Or Paid	Balance at End of Period
Deducted From the Asset to Which it Applies – Allowance for doubtful accounts for the years ended:					
June 30, 2008	$ 300,000	$ 599,345	$ 64,139	$ 498,484	$ 465,000
June 30, 2007	520,000	272,893	9,824	502,717	300,000
June 30, 2006	310,000	705,474	134,325	629,799	520,000

EXHIBIT 12

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
COMPUTATION OF THE CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	2008	2007	2006	2005	2004
Earnings					
Net income	**$ 6,829,868**	$ 5,298,347	$ 5,024,635	$ 4,998,619	$ 3,838,059
Provisions for income taxes (a)	**4,146,900**	3,156,700	2,982,900	3,138,800	2,391,100
Fixed charges	**4,796,489**	4,673,261	5,006,608	4,494,445	4,424,777
Total	**$ 15,773,257**	$ 13,128,308	$ 13,014,143	$ 12,631,864	$ 10,653,936
Fixed Charges					
Interest on debt (a)	**$ 4,383,223**	$ 4,260,179	$ 4,704,075	$ 4,229,261	$ 4,158,988
Amortization of debt	**387,266**	387,082	273,533	236,184	236,789
One third of rental expense	**26,000**	26,000	29,000	29,000	29,000
Total	**$ 4,796,489**	$ 4,673,261	$ 5,006,608	$ 4,494,445	$ 4,424,777
Ratio of earnings to fixed charges	**3.29x**	2.81x	2.60x	2.81x	2.41x

(a) Interest accrued on uncertain tax positions, in accordance with Financial Accounting Standards Board Interpretation No. 48, is presented in income taxes on the 2008 Consolidated Statement of Income. This interest has been excluded from the determination of fixed charges.

EXHIBIT 21

Subsidiaries of the Registrant

Delgasco, Inc., Enpro, Inc. and Delta Resources, Inc. are wholly-owned subsidiaries of the Registrant, are incorporated in the state of Kentucky and do business under their corporate names.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 33-104301 of (1) our report dated August 28, 2008 relating to the consolidated financial statements and financial statement schedule of Delta Natural Gas Company, Inc. and subsidiaries (the Company) which report expressed an unqualified opinion on the Company's consolidated financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of new accounting standards in 2008 and 2007 and (2) our report dated August 28, 2008 relating to the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2008.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 28, 2008

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 29, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 29, 2008

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

/s/Glenn R. Jennings

Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

August 29, 2008

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

August 29, 2008

Board of Directors

Left to right, standing:

Lewis N. Melton (a)* (b) Civil Engineer, Vaughn & Melton Consulting Engineers, Inc. (consulting engineering), Middlesboro, Kentucky

Billy Joe Hall (c) Investment Representative, LPL Financial Services (retail investments), Mount Sterling, Kentucky

Michael R. Whitley (a) (b) Lead Director; Retired Vice Chairman of the Board, President and Chief Operating Officer, LG & E Energy Corp. (diversified utility), Louisville, Kentucky

Michael J. Kistner (b) (c)* Consultant, MJK Consulting (financial consulting), Louisville, Kentucky

Arthur E. Walker, Jr. (a) President, The Walker Company (general and highway construction), Mount Sterling, Kentucky

Lanny D. Greer (c) Chairman of the Board and President, First National Financial Corporation and First National Bank (commercial banking), Manchester, Kentucky

Left to right, sitting:

Glenn R. Jennings (b)* Chairman of the Board, President and Chief Executive Officer

Harrison D. Peet Director Emeritus; Retired Chairman of the Board, President and Chief Executive Officer

Linda K. Breathitt (c) Energy Consultant; Former Senior Energy Advisor, Thelen Reid Brown Raysman & Steiner LLP (law firm); Former Commissioner, Federal Energy Regulatory Commission, Washington, D.C.

(a) Member of Corporate Governance and Compensation Committee
(b) Member of Executive Committee
(c) Member of Audit Committee
*Committee Chair

Left to right:

Johnny L. Caudill Vice President - Administration and Customer Service
Glenn R. Jennings Chairman of the Board, President and Chief Executive Officer
John B. Brown Chief Financial Officer, Treasurer and Secretary
Alan L. Heath Vice President - Operations and Engineering

Corporate Information

SHAREHOLDERS' INQUIRIES
Communications regarding stock transfer requirements, lost certificates, changes of address or other items may be directed to Computershare Investor Services, LLC, the Transfer Agent and Registrar. Communications regarding dividends, the above items or any other shareholder inquiries may be directed to: Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391, email: ebennett@deltagas.com.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
Deloitte & Touche LLP
Suite 1900
250 East Fifth Street
Cincinnati, Ohio 45202

TRUSTEE AND INTEREST PAYING AGENT FOR DEBENTURES

5.75% due 2021; 7% due 2023

The Bank of New York Trust Company, N.A.
525 Vine Street, Suite 900
Cincinnati, OH 45202

DISBURSEMENT AGENT, TRANSFER AGENT AND REGISTRAR FOR COMMON SHARES; DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN ADMINISTRATOR AND AGENT
Computershare Investor Services, LLC
P.O. Box 43036
Providence, RI 02940-3036
1-888-294-8217

2008 ANNUAL REPORT
This annual report and the financial statements contained herein are submitted to the shareholders of the Company for their general information and not in connection with any sale or offer to sell, or solicitation of any offer to buy, any securities.

2008 ANNUAL MEETING
The annual meeting of shareholders of the Company will be held at the General Office of the Company in Winchester, Kentucky on November 20, 2008, at 10:00 a.m. Proxies for the annual meeting will be requested from shareholders when notice of meeting, proxy statement and form of proxy are mailed on or about October 14, 2008.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN
This plan provides shareholders of record with a convenient way to acquire additional shares of the Company's common stock without paying brokerage fees. Participants may reinvest their dividends and make optional cash payments to acquire additional shares. Computershare Investor Services, LLC administers the Plan and is the agent for the participants. For more information, inquiries may be directed to Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391, e-mail: ebennett@deltagas.com.

Delta Natural Gas Company, Inc.

3617 Lexington Road

Winchester, Kentucky 40391

Phone: 859.744.6171 Fax: 859.744.6552

www.deltagas.com

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to ________

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.
(Exact name of registrant as specified in its charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of principal executive offices)	40391 (Zip code)

859-744-6171
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date: 3,301,117 Shares of Common Stock, Par Value $1.00 Per Share, Outstanding as of September 30, 2008.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(UNAUDITED)

	Three Months Ended September 30,		Twelve Months Ended September 30,	
	2008	2007	2008	2007
OPERATING REVENUES	$ 18,108,090	$ 12,404,170	$ 118,361,037	$ 97,459,212
OPERATING EXPENSES				
Purchased gas	$ 12,323,096	$ 7,909,201	$ 81,296,282	$ 65,406,707
Operation and maintenance	2,826,055	2,896,147	14,058,527	12,792,384
Depreciation and amortization	949,903	1,259,028	3,862,020	4,821,432
Taxes other than income taxes	438,700	442,713	1,807,218	1,847,781
Total operating expenses	$ 16,537,754	$ 12,507,089	$ 101,024,047	$ 84,868,304
OPERATING INCOME (LOSS)	$ 1,570,336	$ (102,919)	$ 17,336,990	$ 12,590,908
OTHER INCOME AND DEDUCTIONS, NET	(8,638)	14,202	60,681	126,520
INTEREST CHARGES	1,145,967	1,209,062	4,707,394	4,681,865
NET INCOME (LOSS) BEFORE INCOME TAXES	$ 415,731	$ (1,297,779)	$ 12,690,277	$ 8,035,563
INCOME TAX EXPENSE (BENEFIT)	142,516	(486,834)	4,776,250	3,011,416
NET INCOME (LOSS)	$ 273,215	$ (810,945)	$ 7,914,027	$ 5,024,147
BASIC AND DILUTED EARNINGS (LOSS) PER COMMON SHARE	$ .08	$ (.25)	$ 2.41	$ 1.54
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (BASIC AND DILUTED)	3,297,671	3,278,556	3,290,273	3,271,031
DIVIDENDS DECLARED PER COMMON SHARE	$ .32	$ .31	$ 1.25	$ 1.225

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	September 30, 2008	June 30, 2008	September 30, 2007
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 885,554	$ 249,859	$ 283,736
Accounts receivable, less allowances for doubtful accounts of $409,000, $465,000 and $180,000, respectively	8,969,495	11,437,219	8,701,983
Gas in storage, at average cost	25,758,024	14,476,393	18,185,078
Deferred gas costs	8,101,290	4,612,752	3,352,647
Materials and supplies, at average cost	577,757	565,333	565,704
Prepayments	3,580,039	2,683,854	3,575,199
Total current assets	$ 47,872,159	$ 34,025,410	$ 34,664,347
PROPERTY, PLANT AND EQUIPMENT	$ 194,253,594	$ 192,127,184	$ 188,349,368
Less-Accumulated provision for depreciation	(68,543,406)	(67,754,068)	(65,854,219)
Net property, plant and equipment	$ 125,710,188	$ 124,373,116	$ 122,495,149
OTHER ASSETS			
Cash surrender value of officers' life insurance	$ 444,312	$ 444,312	$ 425,609
Prepaid pension cost	1,829,872	1,423,932	1,110,665
Regulatory assets	7,632,561	7,713,358	8,240,642
Unamortized debt expense and other	2,774,096	2,834,728	2,937,041
Total other assets	$ 12,680,841	$ 12,416,330	$ 12,713,957
Total assets	$ 186,263,188	$ 170,814,856	$ 169,873,453

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	September 30, 2008	June 30, 2008	September 30, 2007
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 11,076,760	$ 12,154,432	$ 7,271,806
Notes payable	24,698,334	6,828,791	18,589,434
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	1,230,580	1,656,391	1,251,885
Customers' deposits	490,869	505,058	479,465
Accrued interest on debt	862,003	865,727	866,822
Accrued vacation	729,741	720,625	708,277
Deferred income taxes	1,628,913	1,483,700	956,140
Other liabilities	414,047	418,239	454,446
Total current liabilities	$ 42,331,247	$ 25,832,963	$ 31,778,275
LONG-TERM DEBT	$ 58,242,000	$ 58,318,000	$ 58,507,000
DEFERRED CREDITS AND OTHER			
Deferred income taxes	$ 24,516,681	$ 24,576,000	$ 22,301,883
Investment tax credits	169,475	177,800	204,650
Regulatory liabilities	1,948,841	2,144,951	2,394,220
Asset retirement obligations and other	2,193,725	2,171,557	2,038,603
Total deferred credits and other	$ 28,828,722	$ 29,070,308	$ 26,939,356
COMMITMENTS AND CONTINGENCIES (Notes 9 and 10)			
Total liabilities	$ 129,401,969	$ 113,221,271	$ 117,224,631
SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value), 20,000,000 shares authorized; 3,301,117, 3,295,759 and 3,281,814 shares outstanding at September 30, 2008, June 30, 2008 and September 30, 2007, respectively	$ 3,301,117	$ 3,295,759	$ 3,281,814
Premium on common shares	44,106,021	43,967,481	43,620,293
Retained earnings	9,454,081	10,330,345	5,746,715
Total shareholders' equity	$ 56,861,219	$ 57,593,585	$ 52,648,822
Total liabilities and shareholders' equity	$ 186,263,188	$ 170,814,856	$ 169,873,453

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY
(UNAUDITED)

	Three Months Ended September 30,		Twelve Months Ended September 30,	
	2008	2007	2008	2007
COMMON SHARES				
Balance, beginning of period	$ 3,295,759	$ 3,277,106	$ 3,281,814	$ 3,261,034
Dividend reinvestment and stock purchase plan	5,358	4,708	19,303	20,780
Balance, end of period	$ 3,301,117	$ 3,281,814	$ 3,301,117	$ 3,281,814
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 43,967,481	$ 43,508,979	$ 43,620,293	$ 43,146,455
Dividend reinvestment and stock purchase plan	138,540	111,314	485,728	473,838
Balance, end of period	$ 44,106,021	$ 43,620,293	$ 44,106,021	$ 43,620,293
RETAINED EARNINGS				
Balance, beginning of period	$ 10,330,345	$ 7,642,386	$ 5,746,715	$ 4,797,884
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Balance, beginning of period, as adjusted	$ 10,236,045	$ 7,573,756	$ 5,652,415	$ 4,729,254
Net income (loss)	273,215	(810,945)	7,914,027	5,024,147
Dividends declared on common shares (See Consolidated Statements of Income (Loss) for rates)	(1,055,179)	(1,016,096)	(4,112,361)	(4,006,686)
Balance, end of period	$ 9,454,081	$ 5,746,715	$ 9,454,081	$ 5,746,715
COMMON SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 57,593,585	$ 54,428,471	$ 52,648,822	$ 51,205,373
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Balance, beginning of period, as adjusted	$ 57,499,285	$ 54,359,841	$ 52,554,522	$ 51,136,743
Net income (loss)	273,215	(810,945)	7,914,027	5,024,147
Issuance of common stock	143,898	116,022	505,031	494,618
Dividends on common stock	(1,055,179)	(1,016,096)	(4,112,361)	(4,006,686)
Balance, end of period	$ 56,861,219	$ 52,648,822	$ 56,861,219	$ 52,648,822

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Twelve Months Ended September 30, 2008	Twelve Months Ended September 30, 2007
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss)	$ 273,215	$ (810,945)	$ 7,914,027	$ 5,024,147
Adjustments to reconcile net income (loss) to net cash from operating activities				
Depreciation and amortization	1,076,688	1,374,143	4,362,955	5,281,869
Deferred income taxes and investment tax credits	61,519	(569,977)	2,726,496	1,805,673
Gain on sale of asset	(156,023)	—	(172,978)	—
Other - net	(185,239)	(57,752)	(355,511)	(192,155)
Increase in assets	(13,886,063)	(8,584,798)	(14,843,833)	(5,245,993)
Increase (decrease) in liabilities	(1,673,783)	(2,513,700)	3,620,755	1,398,699
Net cash provided by (used in) operating activities	$ (14,489,686)	$ (11,163,029)	$ 3,251,911	$ 8,072,240
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (2,108,265)	$ (2,136,987)	$ (5,520,984)	$ (8,329,019)
Proceeds from sale of property, plant and equipment	351,384	14,490	634,321	130,167
Net cash used in investing activities	$ (1,756,881)	$ (2,122,497)	$ (4,886,663)	$ (8,198,852)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common stock	$ (1,055,179)	$ (1,016,096)	$ (4,112,361)	$ (4,006,686)
Issuance of common stock, net	143,898	116,022	505,031	494,618
Long-term debt issuance expense	—	—	—	(5,000)
Repayment of long-term debt	(76,000)	(118,000)	(265,000)	(283,000)
Borrowings on bank line of credit	31,416,621	22,108,452	73,911,126	55,353,670
Repayment of bank line of credit	(13,547,078)	(7,708,936)	(67,802,226)	(51,336,503)
Net cash provided by financing activities	$ 16,882,262	$ 13,381,442	$ 2,236,570	$ 217,099
NET INCREASE IN CASH AND CASH EQUIVALENTS	$ 635,695	$ 95,916	$ 601,818	$ 90,487
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	249,859	187,820	283,736	193,249
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 885,554	$ 283,736	$ 885,554	$ 283,736

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 38,000 customers. Our distribution and transmission systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(2) All adjustments necessary for a fair presentation of the unaudited results of operations for the three and twelve months ended September 30, 2008 and 2007 are included. All such adjustments are accruals of a normal and recurring nature. The results of operations for the periods ended September 30, 2008 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve month ended financial information is provided for additional information only. The accompanying consolidated financial statements are unaudited and should be read in conjunction with the financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended June 30, 2008.

(3) Pursuant to Financial Accounting Standards Board Interpretation No. 48, we recognize a liability for unrecognized tax positions for those tax positions taken on tax returns which are not deemed more likely than not to be sustained on examination by the taxing authorities. In fiscal 2008, we filed a method change with the Internal Revenue Service related to the timing of deducting certain expenses. During the quarter ended September 30, 2008, we received approval for the method change. As a result of the method change, our liability for unrecognized tax positions decreased $265,000 of which $45,000 represented interest previously accrued on the unrecognized tax position and $220,000 represented deferred taxes on the unrecognized tax position.

(4) In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 contains provisions relating to disclosure and recognition which we adopted effective June 30, 2007. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Effective July 1, 2008, we adopted the measurement date provision of Statement No. 158, which required us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are $760,000. Of this amount, $152,000 was attributable to the change in measurement dates. Accordingly, we recognized a $119,000 decrease in our prepaid pension and a $33,000 decrease in our unrecovered pension expense regulatory asset. These decreases were accounted for as a reduction to beginning retained earnings as of July 1, 2008, net of $58,000 of tax.

(5) In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February, 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. Both statements were effective for us beginning July 1, 2008. The statements define fair value, establish a framework for measuring fair value in generally accepted accounting principles and expand disclosures about fair value measurements. Upon adoption, these statements did not have a material impact on our results of operations or financial positions.

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of Financial Accounting Standards Board Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

(6) In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged instruments are accounted for under Statement No. 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We do not expect this statement, which shall be effective for our quarter ending March 31, 2009, to have an impact on our results of operations or financial position.

(7) We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	September 30, 2008	June 30, 2008	September 30, 2007
Unbilled revenues ($)	1,677	1,579	1,237
Unbilled gas costs ($)	835	736	618
Unbilled volumes (Mcf)	48	51	51

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(8) Net pension costs for our trusteed, noncontributory defined benefit pension plan for the periods ended September 30 include the following:

($000)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Twelve Months Ended September 30, 2008	Twelve Months Ended September 30, 2007
Service cost	169	187	730	724
Interest cost	203	187	762	712
Expected return on plan assets	(253)	(247)	(993)	(994)
Amortization of unrecognized net loss	55	62	242	236
Amortization of prior service cost	(22)	(21)	(86)	(84)
Net periodic benefit cost	152	168	655	594

(9) The current available bank line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $24,698,000, $6,829,000 and $18,589,000 were borrowed having a weighted average interest rate of 3.24%, 3.21% and 6.72%, as of September 30, 2008, June 30, 2008 and September 30, 2007, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The annual cost of the unused bank line of credit is .125% and the bank line of credit extends through October 31, 2009.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(10) We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $2.9 million would be paid in addition to continuation of specified benefits for up to five years.

(11) We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

(12) The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and our transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas distribution and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness, and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually, beginning in February, 2009, to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

(13) Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the sale or transportation of natural gas. Price risk for the regulated segment is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated segment is mitigated by efforts to balance supply and

demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided $4,627,000 and $17,902,000 of non-regulated revenues for the three and twelve months ended September 30, 2008, respectively. Citizens Gas Utility District provided $2,161,000 and $9,870,000 of non-regulated revenues for the three and twelve months ended September 30, 2007, respectively. There is no assurance that revenues from them will continue at these levels.

For the three and twelve months ended September 30, 2008 and 2007, we purchased approximately 99% of our natural gas from interstate sources. We utilize Atmos Energy Marketing and M & B Gas Services to fulfill our interstate purchase requirements.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2008. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenue and expense are recorded at our tariff rates. Revenues and expenses for the storage of natural gas is recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown in the following table:

	Three Months Ended September 30,		Twelve Months Ended September 30,	
($000)	2008	2007	2008	2007
Operating Revenues				
Regulated				
External customers	6,649	5,268	59,600	53,615
Intersegment	762	696	4,083	3,582
Total regulated	7,411	5,964	63,683	57,197
Non-regulated				
External customers	11,459	7,136	58,761	43,844
Eliminations for intersegment	(762)	(696)	(4,083)	(3,582)
Total operating revenues	18,108	12,404	118,361	97,459
Net Income (Loss)				
Regulated	(460)	(1,200)	4,096	2,233
Non-regulated	733	389	3,818	2,791
Total net income (loss)	273	(811)	7,914	5,024

(14) During the quarter ended September 30, 2008, we sold two surplus office buildings for $335,000, which resulted in us recording $156,000 of gains on the sales. The gains are included in operation and maintenance expense in the Consolidated Statements of Income (Loss).

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE SEPTEMBER 30, 2008 OVERVIEW AND FUTURE OUTLOOK

For the three months ended September 30, 2008, consolidated net income per share of $0.08 increased $0.33 per share from the consolidated net loss per share of $0.25 for the three months ended September 30, 2007. The increase is due to a $740,000 decrease in the net loss for the regulated segment and a $344,000 increase in net income from our non-regulated segment.

Due to the seasonality of our regulated business, we traditionally incur a consolidated net loss in the first quarter of our fiscal year. The regulated segment historically sells only 6% of its annual volumes during the quarter, while 25% of the annual fixed costs are incurred. However, this loss decreased in the current year due to increased base rates which became effective October 20, 2007. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. Additionally, our non-regulated net income increased due to higher gas prices.

Our 2009 results will be dependent on the winter weather and the extent to which our customers choose to conserve their natural gas usage or discontinue their natural gas service, a trend we have experienced for the last several fiscal years.

We expect our non-regulated segment to continue to contribute to our consolidated net income in fiscal 2009, as in recent years, based on contracts currently in place. Future profitability of the non-regulated segment, though, is dependent on the business plans of a few large customers and the market prices of natural gas, which are both out of our control. If natural gas prices continue to increase, we expect to experience a corresponding increase in our non-regulated margins related to our natural gas production activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income (loss) adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $24,698,000 at September 30, 2008, compared with $6,829,000 at June 30, 2008 and $18,589,000 at September 30, 2007. This increase reflects the seasonal nature of our sales and cash needs. Our cash requirements during the quarters ended September 30, 2008 and 2007 exceeded cash provided by operations, primarily due to the purchase of natural gas which is injected into storage for use during the heating months. Additionally, our liquidity is impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $2,108,000 during the three months ended September 30, 2008. We finance the balance of our capital expenditures on an interim basis through this bank line of credit.

Long-term debt decreased to $58,242,000 at September 30, 2008, compared with $58,318,000 at June 30, 2008 and $58,507,000 at September 30, 2007. These decreases resulted from provisions in the Debentures and Insured Quarterly Notes allowing limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents increased to $886,000 at September 30, 2008, compared with $250,000 at June 30, 2008 and $284,000 at September 30, 2007. These increases in cash and cash equivalents for the three and twelve months ended September 30, 2008 are summarized in the following table:

	Three Months Ended September 30,		**Twelve Months Ended September 30,**	
($000)	**2008**	**2007**	**2008**	**2007**
Provided by (used in) operating activities	(14,489)	(11,163)	3,252	8,072
Used in investing activities	(1,757)	(2,122)	(4,887)	(8,199)
Provided by financing activities	16,882	13,381	2,237	217
Increase in cash and cash equivalents	636	96	602	90

For the three months ended September 30, 2008, cash used in operating activities increased $3,326,000 (30%), as compared with the three months ended September 30, 2007. We paid an additional $7,215,000 for gas due to increased prices and the timing of payables. This increase was partially offset by $5,512,000 more cash received from customers due to higher sales prices (see related discussion in Results of Operations).

For the twelve months ended September 30, 2008, cash provided by operating activities decreased $4,820,000 (60%). We paid an additional $18,434,000 for gas due to higher gas prices and increased quantities purchased. This increase was partially offset by $14,613,000 more cash received from customers due to higher sales prices and the timing of collections.

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

For the three and twelve months ended September 30, 2008, cash provided by financing activities increased $3,501,000 and $2,020,000, respectively, due to increased net borrowings on our bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2009 to be $7.9 million.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short-term and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that internally generated cash is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available line of credit is $40,000,000, of which $24,698,000 was borrowed at September 30, 2008 and classified as notes payable on the accompanying Consolidated Balance Sheets. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices, and we continuously monitor our need to file rate requests with the Kentucky Public Service Commission for a general rate increase for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. This rate case requested a return on common equity of 12.1%. During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenue from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented on the Consolidated Statements of Income (Loss) is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three and twelve months ended September 30, 2008 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

	2008 compared to 2007	
($000)	Three Months Ended September 30,	Twelve Months Ended September 30,
Increase (decrease) in regulated gross margins		
Gas sales	563	1,975
On-system transportation	25	305
Off-system transportation	107	796
Other	(39)	(415)
Total	656	2,661
Increase in non-regulated gross margins		
Gas sales	605	2,243
Other	29	109
Total	634	2,352
Increase in consolidated gross margins	1,290	5,013
Percentage increase (decrease) in regulated volumes		
Gas sales	(7)	(5)
On-system transportation	(7)	(3)
Off-system transportation	9	24
Percentage increase in non-regulated gas sales volumes	6	11

Heating degree days were 95% of normal thirty year average temperatures for the twelve months ended September 30, 2008 as compared with 93% of normal temperatures in 2007. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended September 30, 2008, consolidated gross margins increased $1,290,000 (29%) due to increases in our regulated and non-regulated gross margins of $656,000 (21%) and $634,000 (45%), respectively. Our regulated margin for gas sales increased $563,000 (27%) primarily due to increased base rates which became effective October 20, 2007. Our regulated off-system transportation gross margins increased $107,000 (13%) primarily due to a 9% increase in volumes transported. Our non-regulated gross margins increased $634,000 (45%) due to higher sales prices.

For the twelve months ended September 30, 2008, consolidated gross margins increased $5,013,000 (16%) due to increases in our regulated and non-regulated gross margins of $2,661,000 (12%) and $2,352,000 (25%), respectively. Our regulated margin for gas sales increased $1,975,000 (11%) primarily due to increased base rates which became effective October 20, 2007. Our regulated off-system transportation gross margins increased $796,000 (25%) primarily due to a 24% increase in volumes transported. Our non-regulated gross margins increased $2,352,000 (25%) due to higher sales prices.

Operation and Maintenance

For the three months ended September 30, 2008, operation and maintenance decreased $70,000 (2%) due to $156,000 of gains on the sales of two surplus buildings. These gains were partially offset by increases due to the timing of certain expenses as compared to the three months ended September 30, 2007.

For the twelve months ended September 30, 2008, operations and maintenance increased $1,267,000 (10%) due to increased uncollectible expense ($416,000), increased storage maintenance expense ($317,000), increased labor expense ($225,000), increased transportation expenses ($206,000) and increased maintenance of transmission and distribution mains ($139,000). These increases were partially offset by $156,000 of gains on the sales of two surplus buildings.

Depreciation and Amortization

For the three and twelve months ended September 30, 2008, depreciation and amortization decreased $309,000 (25%) and $959,000 (20%). The decreases were due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decreases were partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Income Tax Expense (Benefit)

For the three and twelve months ended September 30, 2008, income tax expense increased $630,000 (129%) and $1,765,000 (59%) as a result of changes in net income (loss) before income taxes.

Basic and Diluted Earnings Per Common Share

For the three and twelve months ended September 30, 2008 and 2007, our basic earnings (loss) per common share changed as a result of changes in net income (loss) and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings (loss) per common share and our diluted earnings (loss) per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement of Financial Accounting Standards No. 133, entitled Accounting for Derivatives Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balances on our bank line of credit were $24,698,000, $6,829,000 and

$18,589,000 on September 30, 2008, June 30, 2008 and September 30, 2007, respectively. The weighted average interest rates on our bank line of credit were 3.24%, 3.21% and 6.72% on September 30, 2008, June 30, 2008 and September 30, 2007, respectively. Based on the amounts of our outstanding bank line of credit on September 30, 2008, June 30, 2008 and September 30, 2007, a one percent (one hundred basis point) increase in our average interest rates would result in decreases in our annual pre-tax net income of $247,000, $68,000 and $186,000, respectively.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's ("SEC's") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of September 30, 2008, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC's rules and forms.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended September 30, 2008. During the quarter ended September 30, 2008, we implemented a new gas accounting system. As part of the system implementation we have reviewed the controls affected by the new system and have modified our internal controls accordingly. Although we do not believe that our prior gas accounting system had any significant deficiencies or material weaknesses, we expect the implementation of the new system to enhance our internal control over financial reporting. Except as described above, there were no changes in our internal control over financial reporting during the fiscal quarter ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: November 7, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: November 7, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 31.2

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: November 7, 2008

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal
Accounting Officer)

Exhibit 32.1

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: November 7, 2008

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: November 7, 2008

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer
(Duly Authorized Officer)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934

November 20, 2008

Date of Report (Date of earliest event reported)

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	0-8788	61-0458329
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	(Zip Code)

859-744-6171

Registrant's telephone number, including area code

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.02 Departure of Directors or Principal Officers; Election of Directors; Appointment of Principal Officers.

Alan L. Heath, Vice President – Operations & Engineering, will retire from Delta Natural Gas Company, Inc. after twenty four years of service, effective December 31, 2008. Mr. Heath's term as an officer of Delta ended November 20, 2008, terminating his change in control agreement with Delta.

On November 20, 2008, Delta's Board of Directors appointed Johnny L. Caudill to serve as Vice President – Distribution for one year or until his successor is elected and qualified. Mr. Caudill, age 59, has been with the Company since 1972 and has been Vice President – Administration & Customer Service since 1995. On November 20, 2008, Delta's Board of Directors set Mr. Caudill's annual base compensation at $175,000, effective December 1, 2008. Mr. Caudill retains his change in control agreement as filed in Delta's Form 10-Q (File No. 000-08788) for the period ended March 31, 2000. The agreement provides, in the event of a change in control, for up to three years of continuing monthly salary payments and benefits to Mr. Caudill. If during that period Mr. Caudill is terminated without cause, his salary and benefits continue for the remainder of the contract term (but in no event for less than two years), and he may elect to receive his total remaining base salary as a lump sum payment. A termination by Mr. Caudill because he determines in good faith that his employment is not in the company's best interests or that he is unable to carry out his duties effectively is considered a "without cause" termination.

On November 20, 2008, Delta's Board of Directors appointed Brian S. Ramsey to serve as Vice President – Transmission and Gas Supply for one year or until his successor is elected and qualified. Mr. Ramsey, age 45, has been with the Company since 1984. He has been Manager – Gas Supply since 2005, and prior to that, he held various positions with the Company, including being named Director – Gas Supply & Transportation in 1997. On November 20, 2008, Delta's Board of Directors set Mr. Ramsey's annual base compensation at $125,000, effective December 1, 2008. The Company entered a change in control agreement with Mr. Ramsey on November 20, 2008, a copy of which is attached as Exhibit 10(a). The agreement provides, in the event of a change in control, for up to three years of continuing monthly salary payments and benefits to Mr. Ramsey. If during that period Mr. Ramsey is terminated without cause, his salary and benefits continue for the remainder of the contract term (but in no event for less than two years), and he may elect to receive his total remaining base salary as a lump sum payment. A termination by Mr. Ramsey because he determines in good faith that his employment is not in the company's best interests or that he is unable to carry out his duties effectively is considered a "without cause" termination.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits:

Exhibit No.	Description
10(a)	Change of control agreement between Registrant and Brian S. Ramsey, dated November 20, 2008

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DELTA NATURAL GAS COMPANY, INC.

Date: November 21, 2008

By: /s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 10(a)

OFFICER AGREEMENT

THIS AGREEMENT, made and entered into this 20th day of November, 2008, by and between DELTA NATURAL GAS COMPANY, INC., a Kentucky Corporation (hereinafter referred to as "Delta" or the "Company"), and Brian S. Ramsey (hereinafter referred to as "Officer").

WITNESSETH:

THAT, WHEREAS, Officer has been employed by Delta in positions of great responsibility; and

WHEREAS, Officer has contributed, and if he remains an executive officer of Delta, it is anticipated will continue to contribute, to the welfare of Delta, its shareholders and customers; and

WHEREAS, Delta desires to retain the services of Officer and provide for continuity of management of Delta in the event of a change in control of Delta; and

WHEREAS, Officer is willing to remain in the employ of Delta following a change of control thereof on the terms and conditions hereinafter set forth.

NOW, THEREFORE, in consideration of the covenants and agreements hereinafter set forth and to induce Officer to remain in the employ of Delta, the parties agree as follows:

1. **OPERATION.** This Agreement shall be effective immediately upon its execution but, anything in this Agreement to the contrary notwithstanding, neither this Agreement nor any of its provisions shall be operative unless and until there has been a Change of Control while Officer is still a corporate officer of Delta, nor shall this Agreement govern or affect Officer's employment relationship with Delta except as explicitly set forth herein. Upon a Change of Control, if Officer is still employed by Delta in the capacity of a corporate officer, this Agreement and all of its provisions shall become operative immediately. If Officer's employment relationship with Delta is terminated before a Change of Control or if the Officer is not at the time of such a Change of Control employed as a corporate officer of Delta, Officer shall have no rights or obligations under this Agreement.

As used herein, "Operative Date" shall mean the date on which a Change of Control occurs.

2. CHANGE IN CONTROL. For the purpose of this Agreement, a "Change of Control" shall mean:

(a) The acquisition by any individual, entity (including the Company), group or "person" (as "person" is defined by Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended [the "Exchange Act"]) of any of the Company's outstanding voting stock if following such acquisition any individual, entity, group or person is beneficial owner (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (i) the then outstanding shares of common stock of the Delta (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of Delta entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that the following acquisitions shall not constitute a Change of Control: (i) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by Delta or any corporation controlled by Delta, or (ii) any acquisition by any corporation pursuant to a reorganization, merger, share exchange, consolidation or similar transaction, if, following such reorganization, merger, share exchange, consolidation or similar transaction, the conditions described in clauses (i), (ii) and (iii) of Subsection (c) of this Section 2 are satisfied; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination of election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of either an actual or threatened election contest (as such terms are used in Rule 14a-11 of Regulation 14A promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Approval by the Company of a reorganization, merger, share exchange, consolidation or similar transaction, in each case, unless, following such reorganization, merger, share exchange, consolidation or similar transaction:

(i) more than 60% of, respectively, the then outstanding shares of common stock of the "Resulting Corporation", as hereinafter defined, and more than 60% of the combined voting power of the then outstanding voting securities of the Resulting Corporation are then beneficially owned, directly or indirectly, by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such reorganization, merger, share exchange, consolidation or similar transaction in substantially the same proportions as their ownership, immediately prior to such reorganization, merger, share exchange, consolidation or similar transaction, of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be (as used herein, "Resulting Corporation" means the surviving company in a merger, consolidation, reorganization or similar transaction and the company in a share exchange (such as, for example, the share exchange that is presently provided for by Kentucky Revised Statutes 271B.11-020) that, pursuant to a statutory share exchange, acquires all of the outstanding shares of another company); and

(ii) no Person (excluding [A] any employee benefit plan (or related trust) of the or the Resulting Corporation, and [B] any Person beneficially owning, immediately prior to such reorganization, merger, share exchange, consolidation or similar transaction, directly or indirectly, 20% or more of the Outstanding Company Common Stock or Outstanding Company Voting Securities, as the case may be) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the Resulting Corporation or the combined voting power of the then outstanding voting securities of the Resulting Corporation entitled to vote generally in the election of directors: and

(iii) at least a majority of the members of the board of directors of the Resulting Corporation were members of the Incumbent Board at the time of the execution of the initial agreement providing for such reorganization, merger, share exchange, consolidation or similar transaction;

or

(d) Approval by the Company of:

(i) a complete liquidation or dissolution of the Company; or

(ii) the sale, lease, exchange or other disposition of all or substantially all of the assets of the Company, other than to a corporation, with respect to which following such sale, lease, exchange or other disposition:

(A) more than 60% of, respectively, the then outstanding shares of common stock of such corporation and the combined voting power of the then outstanding voting securities of such corporation entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly (for example, shares owned by the Company would be "indirectly" owned by the Company's shareholders), by all or substantially all of the individuals or entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such sale, lease, exchange or other disposition in substantially the same proportion as their ownership, immediately prior to such sale, lease, exchange or other disposition, of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be; and

(B) no Person (excluding the Company and any employee benefit plan (or related trust) of the Company or such corporation and any Person beneficially owning, immediately prior to such sale or other disposition, directly or indirectly, 20% or more of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of such corporation and the combined voting power of the then outstanding voting securities of such corporation entitled to vote generally in the election of directors; and

(C) at least a majority of the members of the board of directors of such corporation were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such sale or other disposition of assets of the Company.

3. TERM. Delta agrees that Officer may, at his option, remain in the employ of Delta in a principal executive and managerial capacity at least equal to the position held by Officer on the date before the Operative Date for a period of three years immediately following the Operative Date.

4. COMPENSATION AND BENEFITS. Each year during the three year period immediately following the Operative Date, Officer shall receive compensation consisting of:

(a) A base salary payable semi-monthly, which is not less than the normal rate in effect on the day before the Operative Date, with such increases as may thereafter be awarded in accordance with Delta's regular compensation policies; and

(b) Incentive awards, bonuses, and the like which are not less than the annualized amount of any such awards paid to Officer for the twelve (12) months ending on the Operative Date.

In addition to the foregoing compensation, Officer shall continue to participate, at not less than levels existing on the day before the Operative Date, in Delta's employee benefit plans and practices (or equivalents), including, but not limited to, the retirement plan, employee savings plan, disability plan, vacation plan, stock purchase plan, life insurance and health-and-accident insurance plan and arrangement, company furnished automobile and office, and medical, dental and health plans.

5. TERMINATION. In the event Officer's employment is terminated without cause during said three (3) year period immediately following the Operative Date, Officer shall nevertheless receive all compensation and benefits described in Section 4 hereinabove during said full three year period immediately following the Operative Date, but in no event for less than two (2) years following termination of employment, plus credit for vacation and annual days earned but not taken. In lieu of the continued right to a Company automobile, however, Officer may, in the event of his termination without cause, in his sole discretion, elect to receive, and Delta in such case agrees to convey to Officer, the full, complete and unencumbered title to the automobile then currently being furnished to Officer under the terms of this Agreement. Upon such conveyance, Delta shall no longer have any obligation to furnish Officer with an automobile.

In the event of termination without cause, Officer, in his sole discretion, may elect to receive his total base salary due under Section 4(a) as a lump sum payment. Officer may at any time notify Delta of his determination to receive such lump sum payment, and such payment shall be made by Delta no later than the tenth day following such notification by Officer. An election by Officer to receive a lump sum payment for his base salary shall not affect his right under this Section 5 to participate fully in all other forms of compensation described in Section 4.

As used herein, "termination without cause" shall mean any termination of Officer's employment at the request or demand of Delta except termination for one of the following reasons:

(a) Death of the Officer; or

(b) Retirement of the Officer in accordance with Delta's retirement policy in effect on the day before the Operative Date; or

(c) Conduct or job performance by Officer which, according to an affirmative vote of a majority of the directors still in office who were directors of Delta immediately prior to the Operative Date, materially and adversely affects the administration of his office.

Officer may terminate his employment at any time during the three (3) year period following the Operative Date if the Officer determines in good faith that either (a) his continued employment with Delta is not in the best interests of Delta, or (b) he is unable effectively to carry out his duties and responsibilities as contemplated hereby. Such termination of Officer shall be considered to be "termination without cause".

6. CESSATION OF PAYMENTS. If, at any time while Officer is receiving payments hereunder, he, within any county in which Delta's pipeline facilities are located on the date of execution of this Agreement, directly or indirectly owns, manages, operates, joins, controls, is employed by or participates in the ownership, management, operation or control of, or is connected in any manner with any retail natural gas distribution business, then such payments shall forthwith cease.

7. EXCISE TAX MAKE-WHOLE. In the event it shall be determined that any payment or distribution by Delta to Officer or for Officer's benefit, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (a "Payment"), would be subject to the excise tax imposed by Section 4999 of the Internal Revenue Code of 1986, as amended (the "Code") (or any successor thereto) or comparable state or local tax or any interest or penalties with respect to such excise tax or comparable state or local tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), then Officer shall be entitled to receive additional payment (a "Gross-Up Payment"). The Gross-Up Payment shall be equal to the sum of the Excise Tax and all taxes (including any interest or penalties imposed with respect to such taxes) imposed upon the Gross-Up Payment.

If Officer determines that a Gross-Up Payment is required, Officer shall notify Delta in writing, specifying the amount of Gross-Up Payment required and details as to the calculation thereof. Delta shall, within 30 days, either pay such Gross-Up Payment (net of applicable wage withholding) to Officer or furnish an unqualified opinion from Independent Tax Counsel (as defined below), addressed to Officer and Delta, that there is substantial authority (within the meaning of Section 5551 of the Code) for the position that no Gross-Up Payment is required. "Independent Tax Counsel" means a lawyer with expertise in the area of Officer compensation tax law, who shall be selected by Officer and shall be reasonably acceptable to Delta, and whose fees and disbursements shall be paid by Delta.

If the Internal Revenue Service or other tax authority proposes in writing an adjustment to Officer's income tax that would result in a Gross-Up Payment, Officer shall promptly notify Delta in writing and shall refrain for at least 30 days after giving such notice, if so permitted by law, from paying any tax (including interest, penalties and additions to tax) asserted to be payable as a result of such proposed adjustment. Before the expiration of such period, Delta shall either pay the Gross-Up Payment or provide an opinion from Independent Tax Counsel to Officer and Delta as to whether it is more likely than not that the proposed adjustment would be successfully challenged if the matter were to be litigated. If the opinion provides that a challenge would be more likely than not to be successful if the issues were litigated, and Delta requests in writing that Officer contest such proposed adjustment, then Officer shall contest the proposed adjustment and shall consult in good faith with Delta with respect to the nature of all action to be taken in furtherance of the contest of such proposed adjustment; provided that Officer, after such consultation with Delta, shall determine in Officer's sole discretion the nature of all action to be taken to contest such proposed adjustment, including (A) whether any such action shall initially be by way of judicial or administrative proceedings, or both, (B) whether any such proposed adjustment shall be contested by resisting payment thereof or by paying the same and seeking a refund thereof, and (C) if Officer shall undertake judicial action with respect to such proposed adjustment, the court or other judicial body before which such action shall be commenced and the court or other judicial body to which any appeals should be taken. Officer agrees to take appropriate appeals of any judicial decision that would require Delta to pay a Gross-Up Payment, provided Delta requests in writing that Officer do so and provides an opinion from Independent Tax Counsel to Officer and Delta that it is more likely than not that the appeal would be successful. Officer further agrees to settle, compromise or otherwise terminate a contest with the Internal Revenue Service or other tax authority with respect to all or a portion of the proposed adjustment giving rise to the Gross-Up Payment, if requested by Delta in writing to do so at any time, in which case Officer shall be entitled to receive from Delta the Gross-Up Payment. In no event shall Officer compromise or settle all or any portion of a proposed adjustment which would result in Gross-Up Payment without the written consent of Delta.

Officer shall not be required to take or continue any action pursuant to this Section 7 unless Delta acknowledges its liability under this Agreement in the event that the Internal Revenue Service or other tax authority prevails in the contest. Delta hereby agrees to indemnify Officer in a manner reasonably satisfactory to Officer for any fees, expenses, penalties, interest or additions to tax which Officer may incur as a result of contesting validity of any Excise Tax and to pay Officer promptly upon receipt of a written demand therefor all costs and expenses which Officer may incur in connection with contesting such proposed adjustment (including reasonable fees and disbursements of Independent Tax Counsel); provided, however, that Delta shall not be required to pay any amount necessary to permit Officer's instituting a claim for refund under this Section 7.

If Officer shall have contested any proposed adjustment as above provided, and for so long as Officer shall be required under the terms of this Section 7 to continue such contest, Delta shall not be required to pay a Gross-Up Payment until there occurs a Final Determination (as defined below) of Officer's liability for the tax and any interest, penalties and additions to tax asserted to be payable as a result of such proposed adjustment. A "Final Determination" shall mean (A) a decision, judgment, decree or other order has become final after all allowable appeals by either party to the action have been exhausted, the time for filing such appeal has expired or Officer has no right under the terms thereof to request an appeal, (B) a closing agreement entered into under Section 7121 of the Code or any other settlement agreement entered into in connection with an administrative or judicial proceeding and with Officer's consent, or (C) the expiration of the time for instituting suit with respect thereto.

In the event Officer receives any refund from the Internal Revenue Service or other tax authority on account of an overpayment of Excise Tax, such amount, together with that part of any Gross-Up Payment attributable to such amount, shall be promptly paid by Officer to Delta.

8. PAYMENT OBLIGATIONS ABSOLUTE. Upon a Change of Control Delta's obligations to pay the severance benefits or make any other payments described in this Agreement shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which Delta or any of its subsidiaries may have against the Officer or anyone else. Officer shall not be required to mitigate damages, and if Officer does accept other employment, any benefits or payments hereunder shall not be reduced by any compensation earned or other benefits received as a result of such employment.

9. LEGAL FEES AND EXPENSES. Subject to and contingent upon the occurrence of a Change of Control Delta agrees to pay promptly as incurred, to the full extent permitted by law, all legal fees and expenses which Officer may reasonably thereafter incur as a result of any contest, litigation or arbitration (regardless of the outcome thereof) by Delta, Officer or others of the validity or enforceability of, or liability under, any provision of this Agreement (including any contest by Officer about the amount of any payment pursuant to this Agreement), plus in each case interest on any delayed payment at the rate of 150% of the Prime Rate posted by Bank One, Kentucky, NA.

10. DUE AUTHORIZATION. Delta hereby warrants and represents to Officer that this Agreement has been duly authorized by all necessary corporate action on the part of Delta and has been duly executed by a duly authorized officer of Delta.

11. INDEMNIFICATION

(a) **(1)** As used herein, "Proceeding" means any threatened, pending or completed action, suit or Proceeding, whether civil, criminal, administrative or investigative.

(2) As used herein, "Party" includes a person who was, is or is threatened to be made a named defendant or respondent in a Proceeding.

(3) As used herein, "expenses" include attorneys fees.

(4) As used herein, "Subsidiary" means any company in which Delta is a beneficial owner of 100% of all classes of voting stock.

(b) Delta shall indemnify Officer if he is made a Party to any Proceeding by reason of the fact that he is or was an officer of Delta or Subsidiary if:

(1) He conducted himself in good faith; and

(2) He reasonably believed:

(i) In the case of conduct in his capacity as an officer of Delta or Subsidiary, that his conduct was in Delta's or Subsidiary's best interest; and

(ii) In all other cases, that his conduct was at least not opposed to Delta's or Subsidiary's best interest; and

(iii) In the case of any criminal Proceeding, he had no reasonable cause to believe his conduct was unlawful.

Indemnification shall be made against judgments, penalties, fines, settlements and reasonable expenses actually incurred by Officer in connection with the Proceedings, except that if the Proceeding was by or in the right of Delta or Subsidiary, indemnification shall be made only against such reasonable expenses and shall not be made in respect of any Proceeding which Officer shall have been adjudged to be liable to Delta or Subsidiary. The termination of any Proceeding by judgment, order, settlement, conviction or upon a plea of nolo contendere or its equivalent, shall not, by itself, be determinative that Officer did not meet the requisite standard of conduct set forth in this provision.

(c) In addition to the foregoing Delta or Subsidiary shall, to the full extent permitted by law, indemnify Officer and hold him harmless against any judgments, penalties, fines, settlements and reasonable expenses actually incurred in connection with any Proceeding in which Officer is a Party, provided Officer was made a party to such Proceeding by reason of the fact that he is or was an officer of Delta or Subsidiary or by reason of any inaction, nondisclosure, action or statement made, taken or omitted by or on behalf of Officer with respect to Delta or Subsidiary or by or on behalf of Officer in his capacity as an officer of Delta or Subsidiary.

(d) Reasonable expenses incurred by Officer as a Party to a Proceeding with respect to which indemnity is to be provided shall be paid or reimbursed by Delta in advance of the final disposition of such Proceeding provided:

(1) Delta receives (i) a written affirmation by Officer of his good faith belief that he has met the requisite standard of conduct necessary for indemnification by Delta, as provided in this Agreement, and (ii) Delta receives a written undertaking by or on behalf of Officer to repay such amount if it shall ultimately be determined that he has not met such standard of conduct; and

(2) Delta's Board of Directors (or other appropriate decision maker for Delta) determines that the facts then known to the Board (or decision maker) would not preclude indemnification under this provision.

The undertaking required herein shall be an unlimited general obligation of Officer but shall not require any security and shall be accepted without reference to the financial ability of Officer to make repayment.

(e) Notwithstanding anything herein to the contrary, Officer shall not be indemnified with respect to any Proceeding charging improper personal benefit to him, whether or not involving action in his official capacity, in which he shall have been adjudged to be liable on the basis that personal benefit was improperly received by him.

(f) Delta shall purchase and maintain insurance on behalf of Officer against any liability asserted against him and incurred by him in his capacity or arising out of his status as an officer of Delta or Subsidiary. Such insurance shall provide complete coverage for Officer to the extent reasonably available.

12. BINDING EFFECT; ASSIGNABILITY. This Agreement shall inure to the benefit of and be binding upon Delta, its successors and assigns, including, without limitation, any person, group of persons, partnership or corporation which may acquire substantially all of Delta's assets or business or with which or into which Delta may be liquidated, consolidated, merged or otherwise combined, and shall inure to the benefit of and be binding upon Officer, his heirs and personal representatives. Officer may assign his right to payment under this Agreement, but not his obligations under this Agreement. This Agreement shall not be assigned by Delta without prior written consent of Officer.

13. SEVERABILITY. If any term, provision, covenant or restriction of this Agreement is held by a court of competent jurisdiction to be invalid, void or unenforceable, the remainder of the terms, provisions, covenants and restrictions of this Agreement shall remain in full force and effect and shall in no way be affected, impaired or invalidated.

14. AMENDMENTS. This Agreement may not be modified, amended, altered or supplemented except upon the execution and delivery of a written agreement by the parties hereto.

15. PREVIOUS AGREEMENTS. This Agreement supercedes and replaces any and all previous or existing such similar agreements between Officer and Delta.

16. NOTICES. All notices, requests, claims, demands and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given if so given) if delivered in person, by telegram or facsimile transmission, or by registered or certified mail, postage pre-paid, return receipt requested) to the respective parties as follows:

If to Delta:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
Attention: President

If to Officer:

Brian S. Ramsey
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391

or to such other address as either party may have furnished to the other in writing in accordance herewith, except that notices of change of address shall only be effective upon receipt.

17. GOVERNING LAW. This Agreement shall be construed in accordance with the laws of the Commonwealth of Kentucky.

18. EFFECT OF HEADINGS. The Section headings herein are for convenience only and shall no affect the construction hereof.

IN WITNESS WHEREOF, the parties hereby have caused this Agreement to be executed the day and year first above written.

DELTA NATURAL GAS COMPANY, INC.

BY: ______________________________
Chairman of the Board, President
and Chief Executive Officer

____
Brian S. Ramsey

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to _______

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.
(Exact name of registrant as specified in its charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of principal executive offices)	40391 (Zip code)

859-744-6171
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date:
3,307,446 Shares of Common Stock, Par Value $1.00 Per Share, Outstanding as of December 31, 2008.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended December 31,		Six Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007	2008	2007
OPERATING REVENUES	$33,957,969	$29,298,418	$52,066,058	$41,702,589	$123,020,587	$ 98,323,415
OPERATING EXPENSES						
Purchased gas	$24,081,852	$19,335,440	$36,404,948	$27,244,641	$ 86,042,694	$ 66,008,819
Operation and maintenance	5,155,649	3,189,731	7,981,705	6,085,879	16,024,446	12,939,068
Depreciation and amortization	961,383	1,043,289	1,911,286	2,302,318	3,780,114	4,783,875
Taxes other than income taxes	445,575	440,276	884,275	882,989	1,812,515	1,846,286
Total operating expenses	$30,644,459	$24,008,736	$47,182,214	$36,515,827	$107,659,769	$ 85,578,048
OPERATING INCOME	$ 3,313,510	$ 5,289,682	$ 4,883,844	$ 5,186,762	$ 15,360,818	$ 12,745,367
OTHER INCOME AND DEDUCTIONS, NET	(78,620)	5,197	(87,257)	19,400	(23,136)	113,401
INTEREST CHARGES	1,264,211	1,330,863	2,410,177	2,539,925	4,640,742	4,754,460
NET INCOME BEFORE INCOME TAXES	$ 1,970,679	$ 3,964,016	$ 2,386,410	$ 2,666,237	$ 10,696,940	$ 8,104,308
INCOME TAX EXPENSE	741,675	1,508,731	884,191	1,021,897	4,009,194	3,005,697
NET INCOME	$ 1,229,004	$ 2,455,285	$ 1,502,219	$ 1,644,340	$ 6,687,746	$ 5,098,611
BASIC AND DILUTED EARNINGS PER COMMON SHARE	$ .37	$ .75	$ .46	$ .50	$ 2.03	$ 1.56
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (BASIC AND DILUTED)	3,303,313	3,283,130	3,300,403	3,280,704	3,295,341	3,276,034
DIVIDENDS DECLARED PER COMMON SHARE	$ .32	$ .31	$ .64	$ .62	$ 1.26	$ 1.23

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	December 31, 2008	June 30, 2008	December 31, 2007
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 324,863	$ 249,859	$ 680,811
Accounts receivable, less allowances for doubtful accounts of $852,000, $465,000 and $252,000, respectively	18,602,820	11,437,219	19,648,063
Gas in storage, at average cost	21,183,038	14,476,393	16,391,139
Deferred gas costs	6,032,930	4,612,752	3,377,138
Materials and supplies, at average cost	588,409	565,333	503,029
Prepayments	4,178,350	2,683,854	3,862,022
Total current assets	$ 50,910,410	$ 34,025,410	$ 44,462,202
PROPERTY, PLANT AND EQUIPMENT	$ 195,391,491	$ 192,127,184	$ 189,900,707
Less-Accumulated provision for depreciation	(69,259,827)	(67,754,068)	(66,640,646)
Net property, plant and equipment	$ 126,131,664	$ 124,373,116	$ 123,260,061
OTHER ASSETS			
Cash surrender value of officers' life insurance	$ 384,940	$ 444,312	$ 425,609
Prepaid pension cost	1,677,932	1,423,932	943,100
Regulatory assets	7,648,521	7,713,358	8,203,349
Unamortized debt expense and other	2,758,250	2,834,728	2,944,110
Total other assets	$ 12,469,643	$ 12,416,330	$ 12,516,168
Total assets	$ 189,511,717	$ 170,814,856	$ 180,238,431

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	December 31, 2008	June 30, 2008	December 31, 2007
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 8,868,368	$ 12,154,432	$ 9,015,838
Notes payable	28,652,755	6,828,791	23,798,147
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	1,388,248	1,656,391	1,537,290
Customers' deposits	621,511	505,058	611,016
Accrued interest on debt	859,592	865,727	869,543
Accrued vacation	605,410	720,625	593,515
Deferred income taxes	1,628,814	1,483,700	963,559
Other liabilities	470,066	418,239	472,954
Total current liabilities	$ 44,294,764	$ 25,832,963	$ 39,061,862
LONG-TERM DEBT	$ 58,063,000	$ 58,318,000	$ 58,402,000
DEFERRED CREDITS AND OTHER			
Deferred income taxes	$ 25,695,748	$ 24,576,000	$ 23,784,513
Investment tax credits	161,150	177,800	195,700
Regulatory liabilities	1,872,704	2,144,951	2,348,392
Asset retirement obligations and other	2,246,334	2,171,557	2,245,516
Total deferred credits and other	$ 29,975,936	$ 29,070,308	$ 28,574,121
COMMITMENTS AND CONTINGENCIES (Notes 11, 12 and 13)			
Total liabilities	$ 132,333,700	$ 113,221,271	$ 126,037,983
SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value), 20,000,000 shares authorized; 3,307,446, 3,295,759, and 3,286,276 shares outstanding at December 31, 2008, June 30, 2008 and December 31, 2007, respectively	$ 3,307,446	$ 3,295,759	$ 3,286,276
Premium on common shares	44,244,428	43,967,481	43,729,714
Retained earnings	9,626,143	10,330,345	7,184,458
Total shareholders' equity	$ 57,178,017	$ 57,593,585	$ 54,200,448
Total liabilities and shareholders' equity	$ 189,511,717	$ 170,814,856	$ 180,238,431

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(UNAUDITED)

	Six Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
COMMON SHARES				
Balance, beginning of period	$ 3,295,759	$ 3,277,106	$ 3,286,276	$ 3,267,942
Dividend reinvestment and stock purchase plan	11,687	9,170	21,170	18,334
Balance, end of period	$ 3,307,446	$ 3,286,276	$ 3,307,446	$ 3,286,276
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 43,967,481	$ 43,508,979	$ 43,729,714	$ 43,285,686
Dividend reinvestment and stock purchase plan	276,947	220,735	514,714	444,028
Balance, end of period	$ 44,244,428	$ 43,729,714	$ 44,244,428	$ 43,729,714
RETAINED EARNINGS				
Balance, beginning of period	$ 10,330,345	$ 7,642,386	$ 7,184,458	$ 6,183,319
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Beginning retained earnings, as adjusted	$ 10,236,045	$ 7,573,756	$ 7,090,158	$ 6,114,689
Net income	1,502,219	1,644,340	6,687,746	5,098,611
Dividends declared on common shares (See Consolidated Statements of Income for rates)	(2,112,121)	(2,033,638)	(4,151,761)	(4,028,842)
Balance, end of period	$ 9,626,143	$ 7,184,458	$ 9,626,143	$ 7,184,458
SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 57,593,585	$ 54,428,471	$ 54,200,448	$ 52,736,947
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Beginning retained earnings, as adjusted	$ 57,499,285	$ 54,359,841	$ 54,106,148	$ 52,668,317
Net income	1,502,219	1,644,340	6,687,746	5,098,611
Issuance of common stock	288,634	229,905	535,884	462,362
Dividends on common stock	(2,112,121)	(2,033,638)	(4,151,761)	(4,028,842)
Balance, end of period	$ 57,178,017	$ 54,200,448	$ 57,178,017	$ 54,200,448

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ended December 31		Twelve Months Ended December 31	
	2008	2007	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 1,502,219	$ 1,644,340	$ 6,687,746	$ 5,098,611
Adjustments to reconcile net income to net cash from operating activities				
Depreciation and amortization	2,164,858	2,539,549	4,285,720	5,251,341
Deferred income taxes and investment tax credits	1,216,112	895,072	2,416,040	1,798,684
Gain on sale of asset	(156,023)	—	(172,978)	—
Provision for inventory adjustment	1,350,300	—	1,350,300	—
Other, net	(317,632)	(110,014)	(440,646)	(212,879)
Increase in assets	(18,762,084)	(18,830,135)	(9,494,694)	(9,059,542)
Increase (decrease) in liabilities	(3,248,258)	(587,550)	145,312	1,401,008
Net cash provided by (used in) operating activities	$(16,250,508)	$(14,448,738)	$ 4,776,800	$ 4,277,223
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (3,846,171)	$ (2,824,475)	$ (6,571,402)	$ (7,072,264)
Proceeds from sale of property, plant and equipment	426,206	184,708	538,923	272,887
Net cash used in investing activities	$ (3,419,965)	$ (2,639,767)	$ (6,032,479)	$ (6,799,377)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common stock	$ (2,112,121)	$ (2,033,638)	$ (4,151,761)	$ (4,028,842)
Issuance of common stock, net	288,634	229,905	535,884	462,362
Repayment of long-term debt	(255,000)	(223,000)	(339,000)	(268,000)
Borrowings on bank line of credit	53,515,222	41,846,544	76,271,635	59,672,448
Repayment of bank line of credit	(31,691,258)	(22,238,315)	(71,417,027)	(53,020,647)
Net cash provided by financing activities	$ 19,745,477	$ 17,581,496	$ 899,731	$ 2,817,321
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	$ 75,004	$ 492,991	$ (355,948)	$ 295,167
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	249,859	187,820	680,811	385,644
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 324,863	$ 680,811	$ 324,863	$ 680,811

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(2) All adjustments necessary for a fair presentation of the unaudited results of operations for the three, six and twelve months ended December 31, 2008 and 2007 are included. All such adjustments are accruals of a normal and recurring nature other than the inventory adjustment discussed in Note 12 to record a reserve against our gas in storage. The results of operations for the periods ended December 31, 2008 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve months ended financial information is provided for additional information only. The accompanying consolidated financial statements are unaudited and should be read in conjunction with the consolidated financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended June 30, 2008.

(3) Pursuant to Financial Accounting Standards Board Interpretation No. 48, we recognize a liability for unrecognized tax positions for those tax positions taken on tax returns which are not deemed more likely than not to be sustained on examination by the taxing authorities. In fiscal 2008, we filed a method change with the Internal Revenue Service related to the timing of deducting certain expenses. During the quarter ended September 30, 2008, we received approval for the method change. As a result of the method change, our liability for unrecognized tax positions decreased $265,000 of which $45,000 represented interest previously accrued on the unrecognized tax position and $220,000 represented deferred taxes on the unrecognized tax position.

(4) In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 contains provisions relating to disclosure and recognition which we adopted effective June 30, 2007. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Effective July 1, 2008, we adopted the measurement date provision of Statement No. 158, which required us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are $760,000. Of this amount, $152,000 was attributable to the change in measurement dates. Accordingly, we recognized a $119,000 decrease in our prepaid pension and a $33,000 decrease in our unrecovered pension expense regulatory asset. These decreases were accounted for as a reduction to beginning retained earnings as of July 1, 2008, net of $58,000 of tax.

(5) In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February, 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. The Statements define fair value, establish a framework for measuring fair value in accordance with accounting principles generally accepted in the United States of America and expand disclosure requirements about fair value measurements.

Under Statement No. 157, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition under Statement No. 157 focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although Statement No. 157 does not require additional fair value measurements, it applies to other accounting pronouncements that require or permit fair value measurements.

We determine the fair value of financial assets and liabilities based on the following fair value hierarchy, as prescribed by Statement No. 157, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;

- Level 2 – Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

- Level 3 – Unobservable inputs which require the reporting entity to develop its own assumptions.

Effective July 1, 2008, we adopted Statement No. 157 for all financial instruments. There was no cumulative effect adjustment to retained earnings as a result of adopting Statement No. 157.

As of December 31, 2008, our financial assets and liabilities that are measured at fair value on a recurring basis consists of the assets of our supplemental retirement plan. The supplemental retirement plan is a non-qualified deferred compensation plan for Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer. Assets earmarked to pay benefits under the Plan are held by a rabbi trust. As of December 31, 2008, the assets of the plan were $272,000 and are included in unamortized debt expense and other on the Consolidated Balance Sheets. The offsetting liability of the plan is included in asset retirement obligations and other on the Consolidated Balance Sheets. The liability of the plan is not considered a financial liability within the scope of Statement No. 157. The assets of the plan are recorded at fair value and consist of cash and cash equivalents and mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the Statement No. 157 hierarchy.

Our Debentures and Insured Quarterly Notes are stated at historical cost.

Statement No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Although Statement No. 159 was effective for our fiscal year beginning July 1, 2008, we do not currently have any financial assets or financial liabilities for which the provisions of Statement No. 159 has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with this standard.

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of Financial Accounting Standards Board Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

(6) In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged instruments are accounted for under Statement No. 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. We do not expect this statement, which shall be effective for our quarter ending March 31, 2009, to have an impact on our results of operations or financial position.

(7) In December, 2008, The Financial Accounting Standards Board issued FASB Staff Position No. FAS 132(R)-1, which amends Statement 132(R), entitled Employers' Disclosures about Pensions and Other Postretirement Benefits, to increase transparency surrounding the types of assets and risks associated in a defined benefit pension or other postretirement plan. Statement 132(R), as amended, will require employers to provide additional disclosure surrounding investment strategies, major categories of plan assets, and valuation techniques used to measure the fair value of plan assets. The staff position, which shall be

effective for our fiscal year ending June 30, 2010, will not have an impact on our results of operations or financial position.

(8) We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	December 31, 2008	June 30, 2008	December 31, 2007
Unbilled revenues ($)	9,591	1,579	6,981
Unbilled gas costs ($)	6,788	736	4,224
Unbilled volumes (Mcf)	517	51	425

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(9) Net pension costs for our trusteed, noncontributory defined benefit pension plan for the periods ended December 31 include the following:

	Three Months Ended December 31,		Six Months Ended December 31,		Twelve Months Ended December 31,	
($000)	2008	2007	2008	2007	2008	2007
Service cost	169	187	339	374	713	732
Interest cost	203	187	405	373	778	723
Expected return on plan assets	(253)	(247)	(505)	(494)	(999)	(992)
Amortization of unrecognized net loss	55	62	108	125	233	242
Amortization of prior service cost	(22)	(21)	(43)	(43)	(86)	(86)
Net periodic benefit cost	152	168	304	335	639	619

(10) The current available bank line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $28,653,000, $6,829,000 and $23,798,000 were borrowed having a weighted average interest rate of 2.66%, 3.21% and 5.99% as of December 31, 2008, June 30, 2008 and December 31, 2007, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The annual cost of the unused bank line of credit is .125% and the bank line of credit extends through October 31, 2009.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(11) We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $3 million would be paid in addition to continuation of specified benefits for up to five years.

(12) We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records. During January, 2009, after analyzing the storage field data at the end of the 2008 injection cycle, we determined that an inventory adjustment was required. We estimate that the adjustment amount will be in the range of $1,350,000 to $1,750,000. Based on the storage field data currently available, we cannot determine if any amount within the range is more likely than any other. The October, 2008 storage field data suggested that the inventory adjustment is related to a storage well that was identified in 2007 as allowing natural gas to escape. The storage well was remediated during fiscal 2008.

Prior to the current reporting period, sufficient data has not been available to determine the amount of lost gas inventory resulting from the compromised storage well. Prior to this current fiscal quarter, however, we had no reason to believe this represented a material financial risk to the Company. Our analysis in January, 2009 indicates a material shortfall of storage gas volumes in comparison with our perpetual inventory records. The January, 2009 analysis has also provided us enough information to estimate a range for adjusting inventory.

We have thus recorded a reserve in the amount of $1,350,000 against gas in storage on our December 31, 2008 Consolidated Balance Sheet. The reserved amount is included in operation and maintenance expense in the Consolidated Statements of Income for the three, six and twelve months ended December 31, 2008. Any future adjustment to the inventory reserve will be determined as additional storage field data is collected and evaluated during future storage injection and withdrawal cycles. The underground storage facility is insured against certain risks such as this, and although we intend to seek appropriate reimbursement from the insurer we cannot predict the amount of any insurance proceeds. Depending on the outcome of our pursuit of insurance recovery, we will also evaluate whether any unreimbursed gas losses are eligible for regulatory recovery under our gas cost recovery rate mechanism, or other appropriate methods. We have not recorded any insurance recovery asset or regulatory asset in the accompanying financial statements; however, to the extent recovery becomes probable, we will evaluate recognition of an asset at that time.

(13) We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

(14) The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and our transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas distribution and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness, and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates will be adjusted annually, beginning in February, 2009, to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

(15) Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the sale or transportation of natural gas. Price risk for the regulated segment is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided \$3,408,000, \$8,035,000 and \$17,747,000 of non-regulated revenues for the three, six and twelve months ended December 31, 2008, respectively. Citizens Gas Utility District provided \$3,563,000, \$5,724,000 and \$10,934,000 of non-regulated revenues for the three, six and twelve months ended December 31, 2007, respectively. Citizens has notified us that they intend to cease purchasing gas from us on March 1, 2009, and we are in discussions with them relative to their future commitments to purchase gas from us. Although we intend to continue to pursue these commitments, there is no assurance that revenues from Citizens will continue at these levels. If Citizens ceases to purchase gas from us, we intend to pursue transporting and selling such gas to other markets.

For the three, six and twelve months ended December 31, 2008 and 2007, we purchased approximately 99% of our natural gas from interstate sources. We utilize Atmos Energy Marketing and M & B Gas Services to fulfill our interstate purchase requirements.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2008. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenue and expense are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown below for the periods:

	Three Months Ended December 31,		Six Months Ended December 31,		Twelve Months Ended December 31,	
($000)	2008	2007	2008	2007	2008	2007
Operating Revenues						
Regulated						
External customers	22,177	16,423	28,826	21,691	65,354	52,699
Intersegment	971	1,086	1,733	1,782	3,970	3,702
Total regulated	23,148	17,509	30,559	23,473	69,324	56,401
Non-regulated						
External customers	11,781	12,875	23,240	20,012	57,667	45,624
Eliminations for intersegment	(971)	(1,086)	(1,733)	(1,782)	(3,970)	(3,702)
Total operating revenues	33,958	29,298	52,066	41,703	123,021	98,323
Net Income						
Regulated	870	1,606	411	406	3,360	2,527
Non-regulated	359	849	1,091	1,238	3,328	2,572
Total net income	1,229	2,455	1,502	1,644	6,688	5,099

(16) During the quarter ended September 30, 2008, we sold two surplus office buildings for $335,000, which resulted in us recording $156,000 of gains on the sales. The gains are included in operation and maintenance expense in the six and twelve months ended December 31, 2008 Consolidated Statements of Income.

(17) Due to the conditions in the worldwide debt and equity markets, we experienced a decline in the value of the assets held by our defined benefit pension plan. Although we are not required to make any minimum contributions during the current year, in January, 2009, we elected to contribute $2,000,000 to the plan.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE DECEMBER 31, 2008 OVERVIEW AND FUTURE OUTLOOK

For the six months ended December 31, 2008, consolidated net income per share of $0.46 decreased $0.04 per share as compared to the $0.50 net income per share for the six months ended December 31, 2007. The decrease is attributable to a non-recurring inventory adjustment to record a reserve against our gas in storage of $1,350,000 ($838,000 net of income tax benefit), as further discussed in Note 12 of the Notes to Consolidated Financial Statements. The decrease was substantially offset by increased gross margins for both our regulated and non-regulated segments.

Our 2009 results will be dependent on the winter weather and the extent to which our customers choose to conserve their natural gas usage or discontinue their natural gas service, a trend we have experienced for the last several fiscal years.

We expect our non-regulated segment to continue to contribute to our consolidated net income in fiscal 2009, as in recent years, based on contracts currently in place. Future profitability of the non-regulated segment, though, is dependent on the business plans of a few large customers and the market prices of natural gas, which are both out of our control. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment margins related to our natural gas production activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $28,653,000 at December 31, 2008, compared with $6,829,000 at June 30, 2008 and $23,798,000 at December 31, 2007. This increase reflects the seasonal nature of our sales and cash needs. Our cash requirements during the six months ended December 31, 2008 and 2007 exceeded cash provided by operations, primarily due to the purchase of natural gas which is injected into storage for use during the heating months. Additionally, our liquidity is impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $3,846,000 and $6,571,000 during the six and twelve months ended December 31, 2008, respectively. We finance the balance of our capital expenditures on an interim basis through our bank line of credit.

Long-term debt decreased to $58,063,000 at December 31, 2008, compared with $58,318,000 at June 30, 2008 and $58,402,000 at December 31, 2007. These decreases resulted from provisions in the Debentures and Insured Quarterly Notes allowing limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents were $325,000 at December 31, 2008, compared with $250,000 at June 30, 2008 and $681,000 at December 31, 2007. The changes in cash and cash equivalents for six and twelve months ended December 31, 2008 are summarized in the following table:

	Six Months Ended December 31,		Twelve Months Ended December 31,	
($000)	2008	2007	2008	2007
Provided by (used in) operating activities	(16,250)	(14,449)	4,777	4,277
Used in investing activities	(3,420)	(2,639)	(6,032)	(6,799)
Provided by financing activities	19,745	17,581	899	2,817
Increase (decrease) in cash and cash equivalents	75	493	(356)	295

For the six months ended December 31, 2008, cash used in operating activities increased $1,801,000 (12%), as compared with the six months ended December 31, 2007. Cash paid for taxes increased $889,000 due to the timing of property tax payments between years. We also used an additional $796,000 in operating activities due to the timing of contributions to our pension plan, increased payroll, increased cost of removal and increases in other operating expenses.

For the twelve months ended December 31, 2008, cash provided by operating activities increased $500,000 (12%), as compared with the twelve months ended December 31, 2007, due to an increase in cash received from customers due to higher sales prices and increased volumes sold and transported. This increase was partially offset by an increase in cash paid for gas due to higher natural gas prices and increases in cash paid for other operating expenses.

Changes in cash used in investing activities result primarily from the changes in capital expenditures between periods.

For the six months ended December 31, 2008, cash provided by financing activities increased $2,164,000 (12%) due to increased net borrowings on our bank line of credit.

For the twelve months ended December 31, 2008, cash provided by financing activities decreased $1,918,000 (68%) due to increased net repayments on our bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2009 to be $7.9 million.

Due to volatile conditions in the debt and equity markets we experienced a decline in the value of the assets held by our defined benefit pension plan. Although we are not required to make any minimum contributions during the current year, in January, 2009, we elected to contribute $2,000,000 to the plan. Currently, we do not plan on making any additional contributions to the defined benefit pension plan during the remainder of fiscal 2009. We estimate that this contribution returned the plan to a fully funded status. The decrease in our plan assets could result in an increase in our fiscal 2010 net periodic benefit cost.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

Current economic conditions have resulted in increased credit risk for us due to the potential for default from our customers. For the six and twelve months ended December 31, 2008, we have experienced an increase in customer accounts written off, net of recoveries of $52,000 (23%) and $142,000 (41%), respectively. Based on current outstanding receivables and expecting this trend to continue for the remainder of fiscal 2009, our allowance for doubtful accounts has increased to $852,000 from $465,000 at June 30, 2008 and $252,000 at December 31, 2007. We do not anticipate that this trend will have a materially adverse impact on our liquidity.

To the extent that internally generated cash is not sufficient to satisfy operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit is $40,000,000, of which $28,653,000 was borrowed at December 31, 2008, and was classified as notes payable in the accompanying Consolidated Balance Sheets. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009. We intend to extend our line of credit prior to October 31, 2009.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices and we continuously monitor our need to file rate requests with the Kentucky Public Service Commission for general rate increases for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. This rate case requested a return on common equity of 12.1%. During October, 2007, we negotiated a settlement agreement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenue from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented on the Consolidated Statements of Income, is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three, six and twelve months ended December 31, 2008 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

	2008 compared to 2007		
($000)	Three Months Ended December 31,	Six Months Ended December 31,	Twelve Months Ended December 31,
Increase (decrease) in regulated gross margins			
Gas sales	141	705	1,947
On-system transportation	(16)	9	261
Off-system transportation	89	195	556
Other	140	102	(160)
Total	354	1,011	2,604
Increase (decrease) in non-regulated gross margins			
Gas sales	(413)	191	2,004
Other	(27)	—	56
Total	(440)	191	2,060
Increase in consolidated gross margins	(86)	1,202	4,664
Percentage increase (decrease) in regulated volumes			
Gas sales	20	16	4
On-system transportation	(7)	(7)	(3)
Off-system transportation	8	9	15
Percentage increase (decrease) in non-regulated gas sales volumes	(15)	(7)	3

Heating degree days were 107%, 104% and 103% of normal thirty year average temperatures for the three, six and twelve months ended December 31, 2008, respectively, as compared with 87%, 85% and 92% of normal temperatures in the 2007 periods. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended December 31, 2008, consolidated gross margins decreased $86,000 (1%) due to decreased non-regulated gross margins of $440,000 (16%) offset by increased regulated gross margins of $354,000 (5%). Our non-regulated gross margins decreased $440,000 (16%) due to a 15% decrease in volumes sold. Non-regulated customers are primarily industrial or other large use customers whose volumes are less sensitive to changes in the weather. The decrease in non-regulated volumes was attributable to an overall decrease in our non-regulated customer's gas requirements. Our regulated gross margin for gas sales increased $141,000 (2%) primarily due to a 20% increase in volumes sold due to colder than normal weather which was partially offset by lower rates due to our weather normalization clause. Our regulated transportation and other gross margins increased $213,000 (19%) primarily due to an increase in regulated off-system transportation of 18%.

For the six months ended December 31, 2008, consolidated gross margins increased $1,202,000 (8%) due to increases in our regulated and non-regulated gross margins of $1,011,000 (10%) and $191,000 (5%), respectively. Our regulated gross margin for gas sales increased $705,000 (9%) primarily due to a 16% increase in volumes sold due to colder than normal weather which was partially offset by lower rates due to our weather normalization clause.

Our regulated off-system transportation margins increased $195,000 (11%) due to a 9% increase in volumes transported. Our non-regulated gross margin for gas sales increased $191,000 (5%) due to higher sales prices, partially offset by a 7% decrease in volumes sold.

For the twelve months ended December 31, 2008, consolidated gross margins increased $4,664,000 (14%) due to increases in our regulated and non-regulated gross margins of $2,604,000 (11%) and $2,060,000 (22%), respectively. Our regulated gross margin for gas sales increased $1,947,000 (10%) due to increased base rates which became effective October 20, 2007 as well as a 4% increase in volumes sold. Our regulated off-system transportation margins increased $556,000 (16%) due to a 15% increase in volumes transported. Our non-regulated gross margin for gas sales increased $2,004,000 (22%) due to higher sales prices.

Operations and Maintenance

For the three months ended December 31, 2008, operations and maintenance expense increased $1,966,000 (62%). The increase was due to an inventory adjustment to record a reserve against our gas in storage ($1,350,000, as further discussed in Note 12 of the Notes to Consolidated Financial Statements), increased uncollectible expense ($442,000) and increased employee benefit expense ($155,000).

For the six months ended December 31, 2008, operations and maintenance expense increased $1,896,000 (31%). The increase was due to an inventory adjustment to record a reserve against our gas in storage ($1,350,000, as further discussed in Note 12 of the Notes to Consolidated Financial Statements), increased uncollectible expense ($487,000), increased employee benefit expense ($121,000) and increased labor expense ($120,000), partially offset by $156,000 of gains on the sales of two surplus buildings.

For the twelve months ended December 31, 2008, operations and maintenance expense increased $3,085,000 (24%). The increase was due to an inventory adjustment to record a reserve against our gas in storage ($1,350,000, as further discussed in Note 12 of the Notes to Consolidated Financial Statements), increased uncollectible expense ($891,000), increased storage maintenance expense ($288,000), increased labor expense ($254,000) and increased transportation expense ($148,000).

Depreciation and Amortization

For the six and twelve months ended December 31, 2008, depreciation and amortization decreased $391,000 (17%) and $1,004,000 (21%), respectively. The decreases were due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decreases were partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Income and Deductions, Net

For the six and twelve months ended December 31, 2008, Other Income and Deductions, Net decreased $106,000 (558%) and $136,000 (120%), respectively. The decreases were due to decreases in the cash surrender value of officers' life insurance as well as decreases in the fair value of the supplemental retirement plan. The decrease in the fair value of the supplemental retirement plan was offset by a reduction in operating expenses resulting from a corresponding decrease in the liability of the plan.

Income Tax Expense

For the three and six months ended December 31, 2008, income tax expense decreased $767,000 (51%) and $138,000 (14%), respectively. For the twelve months ended December 31, 2008, income tax expense increased $1,003,000 (33%). These changes are a result of changes in net income before income taxes.

Basic and Diluted Earnings Per Common Share

For the three, six and twelve months ended December 31, 2008 and 2007, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement of Financial Accounting Standards No. 133, entitled Accounting for Derivatives Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balances on our bank line of credit were $28,653,000, $6,829,000 and $23,798,000 on December 31, 2008, June 30, 2008 and December 31, 2007, respectively. The weighted average interest rates on our bank line of credit were 2.66%, 3.21%, and 5.99% on December 31, 2008, June 30, 2008 and December 31, 2007, respectively. Based on the amounts of our outstanding bank line of credit on December 31, 2008, June 30, 2008 and December 31, 2007, a one percent (one hundred basis point) increase in our average interest rates would result in decreases in our annual pre-tax net income of $287,000, $68,000 and $238,000, respectively.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized and reported, within the time periods specified by the Securities and Exchange Commission's ("SEC's") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of the design and operations of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of December 31, 2008, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC's rules and forms.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended December 31, 2008 and found no changes that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The Registrant held its annual meeting of shareholders on November 20, 2008.

(b) Glenn R. Jennings, Lewis N. Melton and Arthur E. Walker, Jr. were elected to Delta's Board of Directors for three-year terms expiring in 2011. Michael J. Kistner and Michael R. Whitley will continue to serve on Delta's Board of Directors until the election in 2009. Linda K. Breathitt, Lanny D. Greer and Billy Joe Hall will continue to serve on Delta's Board of Directors until the election in 2010.

(c) The total shares voted in the election of Directors were 2,941,796. There were no broker non-votes. The shares voted for each Nominee were:

Glenn R. Jennings	For	2,863,362	Withheld	78,434
Lewis N. Melton	For	2,865,956	Withheld	75,840
Arthur E. Walker, Jr.	For	2,850,468	Withheld	91,328

(d) A shareholder recommended in a proposal to the Company's Board of Directors that the Company amend its articles of incorporation to provide for all Directors to stand for election annually and to eliminate director classes with staggered terms. The vote tabulation for all Directors to stand for election annually and to eliminate director classes with staggered terms was:

For	666,737
Against	1,310,189
Abstain	69,627

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: February 3, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: February 3, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: February 3, 2009

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal
Accounting Officer)

Exhibit 32.1

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: February 3, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: February 3, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer
(Duly Authorized Officer)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to _______

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact Name of Registrant as Specified in its Charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of Principal Executive Offices)	40391 (Zip Code)

859-744-6171
(Registrant's Telephone Number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the Issuer's classes of common stock, as of the latest practicable date.
3,313,275 Shares of Common Stock, Par Value $1.00 Per Share, Outstanding as of March 31, 2009.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Nine Months Ended March 31, 2009	Nine Months Ended March 31, 2008	Twelve Months Ended March 31, 2009	Twelve Months Ended March 31, 2008
OPERATING REVENUES	$ 43,160,716	$ 48,396,125	$ 95,226,774	$ 90,098,714	$ 117,785,177	$ 105,697,104
OPERATING EXPENSES						
Purchased gas	$ 30,450,810	$ 33,707,814	$66,855,758	$ 60,952,455	$ 82,785,690	$ 70,952,306
Operation and maintenance	3,333,789	3,384,612	11,315,493	9,470,490	15,973,622	12,890,964
Depreciation and amortization	965,800	929,256	2,877,086	3,231,574	3,816,658	4,503,494
Taxes other than income taxes	490,829	490,007	1,375,105	1,372,996	1,813,338	1,861,358
Total operating expenses	$ 35,241,228	$ 38,511,689	$82,423,442	$ 75,027,515	$104,389,308	$ 90,208,122
OPERATING INCOME	$ 7,919,488	$ 9,884,436	$12,803,332	$ 15,071,199	$ 13,395,869	$ 15,488,982
OTHER INCOME AND DEDUCTIONS, NET	(13,229)	16,963	(100,486)	36,362	(53,327)	108,408
INTEREST CHARGES	1,083,260	1,189,518	3,493,437	3,729,443	4,534,483	4,770,781
NET INCOME BEFORE INCOME TAXES	$ 6,822,999	$ 8,711,881	$ 9,209,409	$ 11,378,118	$ 8,808,059	$ 10,826,609
INCOME TAX EXPENSE	2,563,125	3,290,773	3,447,316	4,312,670	3,281,546	3,972,220
NET INCOME	$ 4,259,874	$ 5,421,108	$ 5,762,093	$ 7,065,448	$ 5,526,513	$ 6,854,389
BASIC AND DILUTED EARNINGS PER COMMON SHARE	$ 1.29	$ 1.65	$ 1.74	$ 2.15	$ 1.67	$ 2.09
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTAND-ING (BASIC AND DILUTED)	3,309,385	3,288,205	3,303,291	3,283,147	3,300,636	3,280,809
DIVIDENDS DECLARED PER COMMON SHARE	$ .32	$ .31	$ .96	$ .93	$ 1.27	$ 1.235

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	March 31, 2009	June 30, 2008	March 31, 2008
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 873,672	$ 249,859	$ 1,944,259
Accounts receivable, less accumulated allowances for doubtful accounts of $943,000, $465,000 and $420,000, respectively	15,260,527	11,437,219	19,860,374
Gas in storage, at average cost	6,937,736	14,476,393	3,315,149
Deferred gas costs	2,702,140	4,612,752	1,900,797
Materials and supplies, at average cost	607,140	565,333	510,897
Prepayments	2,093,397	2,683,854	1,562,618
Total current assets	$ 28,474,612	$ 34,025,410	$ 29,094,094
PROPERTY, PLANT AND EQUIPMENT	$ 198,259,043	$ 192,127,184	$ 190,556,364
Less-Accumulated provision for depreciation	(69,959,549)	(67,754,068)	(66,989,321)
Net property, plant and equipment	$ 128,299,494	$ 124,373,116	$ 123,567,043
OTHER ASSETS			
Cash surrender value of officers' life insurance	$ 378,047	$ 444,312	$ 425,609
Prepaid pension cost	3,525,992	1,423,932	883,123
Regulatory assets	7,623,242	7,713,358	8,150,894
Unamortized debt expense and other	2,692,616	2,834,728	2,886,787
Total other assets	$ 14,219,897	$ 12,416,330	$ 12,346,413
Total assets	$ 170,994,003	$ 170,814,856	$ 165,007,550

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	March 31, 2009	June 30, 2008	March 31, 2008
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 4,140,121	$ 12,154,432	$ 7,080,342
Notes payable	10,658,133	6,828,791	3,287,182
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	2,645,360	1,656,391	4,358,968
Customers' deposits	614,141	505,058	612,802
Accrued interest on debt	855,966	865,727	862,990
Accrued vacation	675,975	720,625	679,701
Deferred income taxes	1,626,836	1,483,700	935,804
Other liabilities	476,480	418,239	412,607
Total current liabilities	$ 22,893,012	$ 25,832,963	$ 19,430,396
LONG-TERM DEBT	$ 57,709,000	$ 58,318,000	$ 58,402,000
DEFERRED CREDITS AND OTHER			
Deferred income taxes	$ 25,720,038	$ 24,576,000	$ 23,816,043
Investment tax credits	152,825	177,800	186,750
Regulatory liabilities	1,863,913	2,144,951	2,305,714
Asset retirement obligations and other	2,155,192	2,171,557	2,132,816
Total deferred credits and other	$ 29,891,968	$ 29,070,308	$ 28,441,323
COMMITMENTS AND CONTINGENCIES (Notes 11, 12 and 13)			
Total liabilities	$ 110,493,980	$ 113,221,271	$ 106,273,719
COMMON SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value), 20,000,000 shares authorized, 3,313,275, 3,295,759 and 3,291,557 shares outstanding at March 31, 2009, June 30, 2008 and March 31, 2008, respectively	$ 3,313,275	$ 3,295,759	$ 3,291,557
Premium on common shares	44,359,433	43,967,481	43,855,846
Retained earnings	12,827,315	10,330,345	11,586,428
Total shareholders' equity	$ 60,500,023	$ 57,593,585	$ 58,733,831
Total liabilities and shareholders' equity	$ 170,994,003	$ 170,814,856	$ 165,007,550

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(UNAUDITED)

	Nine Months Ended March 31,		Twelve Months Ended March 31,	
	2009	2008	2009	2008
COMMON SHARES				
Balance, beginning of period	$ 3,295,759	$ 3,277,106	$ 3,291,557	$ 3,272,687
Dividend reinvestment and stock purchase plan	17,516	14,451	21,718	18,870
Balance, end of period	$ 3,313,275	$ 3,291,557	$ 3,313,275	$ 3,291,557
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 43,967,481	$ 43,508,979	$ 43,855,846	$ 43,399,559
Dividend reinvestment and stock purchase plan	391,952	346,867	503,587	456,287
Balance, end of period	$ 44,359,433	$ 43,855,846	$ 44,359,433	$ 43,855,846
RETAINED EARNINGS				
Balance, beginning of period	$ 10,330,345	$ 7,642,386	$ 11,586,428	$ 8,851,793
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Balance, beginning of period, as adjusted	$ 10,236,045	$ 7,573,756	$ 11,492,128	$ 8,783,163
Net income	5,762,093	7,065,448	5,526,513	6,854,389
Dividends declared on common shares (See Consolidated Statements of Income for rates)	(3,170,823)	(3,052,776)	(4,191,326)	(4,051,124)
Balance, end of period	$ 12,827,315	$ 11,586,428	$ 12,827,315	$ 11,586,428
SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 57,593,585	$ 54,428,471	$ 58,733,831	$ 55,524,039
Adoption of FASB Interpretation No. 48	—	(68,630)	—	(68,630)
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	(94,300)	—	(94,300)	—
Balance, beginning of period, as adjusted	$ 57,499,285	$ 54,359,841	$ 58,639,531	$ 55,455,409
Net income	5,762,093	7,065,448	5,526,513	6,854,389
Issuance of common stock	409,468	361,318	525,305	475,157
Dividends on common stock	(3,170,823)	(3,052,776)	(4,191,326)	(4,051,124)
Balance, end of period	$ 60,500,023	$ 58,733,831	$ 60,500,023	$ 58,733,831

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended March 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 5,762,093	$ 7,065,448	$ 5,526,513	$ 6,854,389
Adjustments to reconcile net income to net cash from operating activities				
Depreciation and amortization	3,257,442	3,594,421	4,323,432	4,981,458
Provision for inventory adjustment	1,350,300	—	1,350,300	—
Deferred income taxes and investment tax credits	1,214,049	873,847	2,435,202	1,802,009
Gain on sale of property, plant and equipment	(156,023)	—	(172,978)	—
Other, net	(327,139)	(153,058)	(393,126)	(212,823)
Decrease (increase) in assets	2,423,508	(2,906,037)	(4,178,745)	(3,928,431)
Increase (decrease) in liabilities	(6,857,006)	689,060	(4,808,487)	1,268,119
Net cash provided by operating activities	$ 6,667,224	$ 9,163,681	$ 4,082,111	$ 10,764,721
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (6,959,987)	$ (3,847,977)	$ (8,661,715)	$ (6,410,292)
Proceeds from sale of property, plant and equipment	457,589	257,929	497,087	310,172
Net cash used in investing activities	$ (6,502,398)	$ (3,590,048)	$ (8,164,628)	$ (6,100,120)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common stock	$ (3,170,823)	$ (3,052,776)	$ (4,191,326)	$ (4,051,124)
Issuance of common stock	409,468	361,318	525,305	475,157
Repayment of long-term debt	(609,000)	(223,000)	(693,000)	(243,000)
Borrowings on bank line of credit	66,476,908	57,005,260	74,074,605	62,976,861
Repayment of bank line of credit	(62,647,566)	(57,907,996)	(66,703,654)	(63,493,313)
Net cash provided by (used in) financing activities	$ 458,987	$ (3,817,194)	$ 3,011,930	$ (4,335,419)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	$ 623,813	$ 1,756,439	$ (1,070,587)	$ 329,182
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	249,859	187,820	1,944,259	1,615,077
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 873,672	$ 1,944,259	$ 873,672	$ 1,944,259

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 38,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(2) All adjustments necessary for a fair presentation of the unaudited results of operations for the three, nine and twelve months ended March 31, 2009 and 2008 are included. All such adjustments are accruals of a normal and recurring nature other than the inventory adjustment discussed in Note 12 to adjust our gas in storage. The results of operations for the periods ended March 31, 2009 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve months ended financial information is provided for additional information only. The accompanying consolidated financial statements are unaudited and should be read in conjunction with the financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended June 30, 2008.

(3) Pursuant to Financial Accounting Standards Board Interpretation No. 48, we recognize a liability for unrecognized tax positions for those tax positions taken on tax returns which are not deemed more likely than not to be sustained on examination by the taxing authorities. In fiscal 2008, we filed a method change with the Internal Revenue Service related to the timing of deducting certain expenses. During the quarter ended September 30, 2008, we received approval for the method change. As a result of the method change, our liability for unrecognized tax positions decreased $265,000, of which $45,000 represented interest previously accrued on the unrecognized tax position and $220,000 represented deferred taxes on the unrecognized tax position.

(4) In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 contains provisions relating to disclosure and recognition which we adopted effective June 30, 2007. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Effective July 1, 2008, we adopted the measurement date provision of Statement No. 158, which required us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 are $760,000. Of this amount, $152,000 was attributable to the change in measurement dates. Accordingly, we recognized a $119,000 decrease in our prepaid pension expense and a $33,000 decrease in our unrecovered pension expense regulatory asset. These decreases were accounted for as a reduction to beginning retained earnings as of July 1, 2008, net of $58,000 of tax.

(5) In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February, 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. The Statements define fair value, establish a framework for measuring fair value in accordance with accounting principles generally accepted in the United States of America and expand disclosure requirements about fair value measurements.

Under Statement No. 157, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition under Statement No. 157 focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although Statement No. 157 does not require additional fair value measurements, it applies to other accounting pronouncements that require or permit fair value measurements.

We determine the fair value of financial assets and liabilities based on the following fair value hierarchy, as prescribed by Statement No. 157, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3 – Unobservable inputs which require the reporting entity to develop its own assumptions.

Effective July 1, 2008, we adopted Statement No. 157 for all financial instruments. There was no cumulative effect adjustment to retained earnings as a result of adopting Statement No. 157.

As of March 31, 2009, our financial assets and liabilities that are measured at fair value on a recurring basis consist of the assets of our supplemental retirement plan. The supplemental retirement plan is a non-qualified deferred compensation plan for Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer. Assets earmarked to pay benefits under the Plan are held by a rabbi trust. As of March 31, 2009, the assets of the plan were $255,000 and are included in unamortized debt expense and other on the Consolidated Balance Sheets. The offsetting liability of the plan is included in asset retirement obligations and other on the Consolidated Balance Sheets. The liability of the plan is not considered a financial liability within the scope of Statement No. 157. The assets of the plan are recorded at fair value and consist of cash and cash equivalents and mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the Statement No. 157 hierarchy.

Our Debentures and Insured Quarterly Notes are stated at historical cost.

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of Financial Accounting Standards Board Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

Statement No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Although Statement No. 159 was effective for our fiscal year beginning July 1, 2008, we do not currently have any financial assets or financial liabilities for which the provisions of Statement No. 159 has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with this standard.

(6) In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged instruments are accounted for under Statement No. 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. Effective March 31, 2009, we adopted the provisions of Statement No. 161. To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. We mitigate price risk by efforts to balance supply and demand. None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement No. 133.

(7) In December, 2008, The Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 132(R)-1, entitled Employer's Disclosures about Postretirement Benefit Plan

Assets, which amends Financial Accounting Standards Board Statement 132(R), entitled Employers' Disclosures about Pensions and Other Postretirement Benefits, to increase transparency surrounding the types of assets and risks associated with a defined benefit pension or other postretirement plan. Statement 132(R), as amended, will require employers to provide additional disclosure surrounding investment strategies, major categories of plan assets, and valuation techniques used to measure the fair value of plan assets. The staff position, which shall be effective for our fiscal year ending June 30, 2010, will not have an impact on our results of operations or financial position.

(8) We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date of the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	March 31, 2009	June 30, 2008	March 31, 2008
Unbilled revenues ($)	6,022	1,579	6,041
Unbilled gas costs ($)	3,660	736	3,763
Unbilled volumes (Mcf)	311	51	360

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(9) Net pension costs for our trusteed, noncontributory defined benefit pension plan for the periods ended March 31 include the following:

	Three Months Ended March 31,		Nine Months Ended March 31,		Twelve Months Ended March 31,	
($000)	2009	2008	2009	2008	2009	2008
Service cost	169	187	508	561	695	740
Interest cost	203	187	608	559	794	734
Expected return on plan assets	(253)	(247)	(758)	(740)	(1,005)	(989)
Amortization of unrecognized net loss	54	62	163	188	225	246
Amortization of prior service cost	(21)	(21)	(65)	(65)	(86)	(86)
Net periodic benefit cost	152	168	456	503	623	645

Due to the conditions in the worldwide debt and equity markets, we experienced a decline in the value of the assets held by our defined benefit pension plan. Although we are not required to make any minimum contributions during the current year, in January, 2009, we elected to contribute $2,000,000 to the plan. Currently, we do not plan on making any additional contributions to the defined benefit pension plan during the remainder of fiscal 2009.

(10) The current available bank line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $10,658,000, $6,829,000 and $3,287,000 were borrowed having a weighted average interest rate of 1.25%, 3.21% and 3.86% as of March 31, 2009, June 30, 2008 and March 31, 2008, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus .75% on the used bank line of credit. The annual cost of the unused bank line of credit is .125% and the bank line of credit extends through October 31, 2009. We intend to extend our bank line of credit prior to October 31, 2009. However, to the extent that we are unable to renew our bank line of credit with BB&T under similar terms, we will seek credit facilities with other financial institutions. However, due to the current volatility in the capital and credit markets, there is no assurance that we would be able to secure financing with similar terms from other financial institutions.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(11) We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $2.9 million would be paid in addition to the continuation of specified benefits for up to five years.

(12) We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records. During January, 2009, after analyzing the storage field data at the end of the 2008 injection cycle, we determined that an inventory adjustment was required. We estimated that the adjustment amount would be in the range of $1,350,000 to $1,750,000. Based on the storage field data currently available, we cannot determine if any amount within the range is more likely than any other. The October, 2008 storage field data suggested that the inventory adjustment is related to a storage well that was identified in 2007 as allowing natural gas to escape. The storage well was remediated during fiscal 2008.

Prior to January, 2009, sufficient data had not been available to determine the amount of lost gas inventory resulting from the compromised storage well. Prior to the quarter ended December 31, 2008, we had no reason to believe this represented a material financial risk to the Company. Our analysis in January, 2009 indicated a material shortfall of storage gas volumes in comparison with our perpetual inventory records. The January, 2009 analysis also provided us enough information to estimate a range for adjusting inventory.

During the quarter ended December 31, 2008, we recorded a gas in storage inventory adjustment in the amount of $1,350,000. The adjustment is included in operation and maintenance expense in the Consolidated Statements of Income for the nine and twelve months ended March 31, 2009. Any future adjustment to inventory will be determined as additional storage field data is collected and evaluated during future storage injection and withdrawal cycles. The underground storage facility is insured against certain risks such as this, and although we have sought appropriate reimbursement from the insurer we cannot predict the amount of any insurance proceeds. Depending on the outcome of our pursuit of insurance recovery, we will also evaluate whether any unreimbursed gas losses are eligible for regulatory recovery under our gas cost recovery rate mechanism, or through other recovery methods. We have not recorded any insurance recovery asset or regulatory asset in the accompanying financial statements; however, to the extent recovery becomes probable, we will evaluate recognition of an asset at that time.

(13) We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

(14) The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and our transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas distribution and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately

$5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenues from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers' interests by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real-time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

(15) Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the distribution or transportation of natural gas. Price risk for the regulated segment is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided $2,213,000, $10,248,000 and $15,500,000 of non-regulated revenues for the three, nine and twelve months ended March 31, 2009, respectively. Citizens Gas Utility District provided $4,460,000, $10,185,000 and $11,498,000 of non-regulated revenues for the three, nine and twelve months ended March 31, 2008, respectively. Citizens has notified us that they intend to decrease their purchases from us, and we are in discussions with them relative to their future commitments to purchase gas from us. There is no assurance that revenues from Citizens will continue at historical levels.

For the three, nine and twelve months ended March 31, 2009 and 2008, we purchased approximately 99% of our natural gas from interstate sources. We utilize Atmos Energy Marketing and M & B Gas Services to fulfill our interstate purchase requirements.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2008. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenue and expense are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown below for the periods:

($000)	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Nine Months Ended March 31, 2009	Nine Months Ended March 31, 2008	Twelve Months Ended March 31, 2009	Twelve Months Ended March 31, 2008
Operating Revenues						
Regulated						
External customers	28,202	27,121	57,028	48,812	66,434	57,083
Intersegment	1,125	1,386	2,858	3,168	3,709	3,872
Total regulated	29,327	28,507	59,886	51,980	70,143	60,955
Non-regulated						
External customers	14,959	21,275	38,199	41,287	51,351	48,614
Eliminations for intersegment	(1,125)	(1,386)	(2,858)	(3,168)	(3,709)	(3,872)
Total operating revenues	43,161	48,396	95,227	90,099	117,785	105,697
Net Income						
Regulated	3,215	3,483	3,625	3,889	3,093	3,707
Non-regulated	1,045	1,938	2,137	3,176	2,434	3,147
Total net income	4,260	5,421	5,762	7,065	5,527	6,854

(16) During the quarter ended September 30, 2008, we sold two surplus office buildings for $335,000, which resulted in us recording $156,000 of gains on the sales. The gains are included in operation and maintenance expense in the nine and twelve months ended March 31, 2009 Consolidated Statements of Income.

(17) In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 107-1 and APB 28-1, entitled Interim Disclosures about Fair Value of Financial Instruments. The staff position amends Financial Accounting Standards Board Statement No. 107, Disclosures about Fair Value of Financial Instruments and Accounting Principles Board Opinion No. 28, entitled Interim Financial Reporting, to require disclosure about the fair value of financial instruments at interim reporting periods. The staff position, which shall be effective for our quarter ending September 30, 2009, will not have an impact on our results of operations or financial position.

In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 157-4, entitled Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. The staff position provides additional guidance for estimating fair value in accordance with Statement No. 157 when the volume and level of activity for the asset or liability have significantly decreased. The staff position, which shall be effective for our fiscal year ending June 30, 2009, will not have an impact on our results of operations or financial position.

In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 115-2 and FAS 124-2, entitled Recognition and Presentation of Other-Than-Temporary Impairments. The staff position provides additional guidance for the presentation and disclosure of other-than-temporary impairments on debt and equity securities. The staff position, which shall be effective for our fiscal year ending June 30, 2009, will not have an impact on our results of operations or financial position.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE MARCH 31, 2009 OVERVIEW AND FUTURE OUTLOOK

For the nine months ended March 31, 2009, consolidated net income per share of $1.74 decreased $0.41 per share as compared to the $2.15 net income per share for the nine months ended March 31, 2008. The decrease is primarily attributable to a non-recurring inventory adjustment for our gas in storage of $1,350,000 ($838,000 net of income tax benefit), as further discussed in Note 12 of the Notes to Consolidated Financial Statements, and decreased gross margins from our non-regulated segment offset by increased gross margins from our regulated segment.

Our regulated segment's contribution to consolidated net income for the remainder of 2009 will be dependent upon the continuing impact the weakened economic environment has on our customers. Our customers may choose to discontinue their natural gas service, be unable to pay for their natural gas service or decrease the volumes purchased from or transported by us on behalf of them.

Future profitability of the non-regulated segment is dependent on the business plans of a few industrial and other large use customers and the market prices of natural gas, all of which are out of our control. For the current quarter ended March 31, 2009, we have experienced a decline in the volumes sold to our non-regulated customers due to a decrease in the non-regulated customers' gas requirements. Although we anticipate our non-regulated segment to continue to contribute to our consolidated net income for the remainder of fiscal 2009, based on the decrease in our non-regulated customer's gas requirements and the contracts currently in place, the non-regulated segment's contribution will be less than in the prior year. Additionally, if natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment margins related to our natural gas production activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes, gains on the sale of assets and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $10,658,000 at March 31, 2009, compared to $6,829,000 at June 30, 2008 and $3,287,000 at March 31, 2008. These increases reflect the seasonal nature of our sales and cash needs. Our liquidity is impacted by the fact that that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $6,960,000 and $8,662,000 during the nine and twelve months ended March 31, 2009, respectively. We finance the balance of our capital expenditures on an interim basis through our bank line of credit.

Long-term debt decreased to $57,709,000 at March 31, 2009, compared with $58,318,000 at June 30, 2008 and $58,402,000 at March 31, 2008. These decreases resulted from the redemption of the Debentures and Insured Quarterly Notes, which allow for limited redemptions to be made to certain holders or their beneficiaries.

Cash and cash equivalents were $874,000 at March 31, 2009, as compared with $250,000 at June 30, 2008 and $1,944,000 at March 31, 2008. These changes in cash and cash equivalents for nine and twelve months ended March 31, 2009 are summarized in the following table:

($000)	Nine Months Ended March 31, 2009	2008	Twelve Months Ended March 31, 2009	2008
Provided by operating activities	6,667	9,163	4,082	10,764
Used in investing activities	(6,502)	(3,590)	(8,165)	(6,100)
Provided by (used in) financing activities	459	(3,817)	3,012	(4,335)
Increase (decrease) in cash and cash equivalents	624	1,756	(1,071)	329

For the nine months ended March 31, 2009, cash provided by operating activities decreased $2,496,000 (27%) primarily due to the $2,000,000 contribution we made to our pension plan in January, 2009, as further discussed in Note 9 of the Notes to Consolidated Financial Statements.

For the twelve months ended March 31, 2009, cash provided by operating activities decreased $6,682,000 (62%) due to the $2,000,000 contribution we made to our pension plan in January, 2009, as further discussed in Note 9 of the Notes to Consolidated Financial Statements, an additional $1,286,000 paid for property taxes, and increases in cash paid for operating expenses.

Changes in cash used in investing activities result primarily from the changes in capital expenditures between periods.

For the nine and twelve months ended March 31, 2009, cash provided by financing activities increased $4,276,000 and $7,347,000, respectively, due to increased net borrowings on our bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2009 to be approximately $9 million.

Due to volatile conditions in the debt and equity markets we experienced a decline in the value of the assets held by our defined benefit pension plan. Although we are not required to make any minimum contributions during the current year, in January, 2009, we elected to contribute $2,000,000 to the plan. Currently, we do not plan on making any additional contributions to the defined benefit pension plan during the remainder of fiscal 2009. We estimate that this contribution returned the plan to a fully funded status. The decrease in the value of our plan assets could result in an increase in our fiscal 2010 net periodic benefit cost.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

Current economic conditions have resulted in increased credit risk for us due to the potential for default from our customers. For the nine and twelve months ended March 31, 2009, we have experienced an increase in customer accounts written off, net of recoveries of $39,000 (13%) and $91,000 (24%), respectively. Based on current outstanding receivables and expecting this trend to continue for the remainder of fiscal 2009, our allowance for doubtful accounts has increased to $943,000 from $465,000 at June 30, 2008 and $420,000 at March 31, 2008. However, we are unable to estimate the impact this trend will have in future earnings and liquidity.

To the extent that internally generated cash is not sufficient to satisfy operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit is $40,000,000, of which $10,658,000 was borrowed at March 31, 2009, and was classified as notes payable on the accompanying Consolidated Balance Sheets. The current bank line of credit is with Branch Banking and Trust Company and extends through October 31, 2009. We intend to extend our bank line of credit prior to October 31, 2009. However, to the extent that we are unable to renew our bank line of credit with BB&T under similar terms, we will seek credit facilities with other financial institutions. However, due to the current volatility in the capital and credit markets, there is no assurance that we would be able to secure financing with similar terms from other financial institutions.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices and we monitor our need to file rate requests with the Kentucky Public Service Commission for general rate increases for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. This rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement agreement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge to partially decouple revenue from volumes of gas sold. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented on the Consolidated Statements of Income, is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three, nine and twelve months ended March 31, 2009 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

($000)	2009 compared to 2008 Three Months Ended March 31,	 Nine Months Ended March 31,	 Twelve Months Ended March 31,
Increase (decrease) in regulated gross margins			
Gas sales	(146)	556	775
On-system transportation	(171)	(160)	(72)
Off-system transportation	(152)	43	185
Other	257	359	242
Total	(212)	798	1,130
Decrease in non-regulated gross margins			
Gas sales	(1,725)	(1,534)	(865)
Other	(41)	(40)	(11)
Total	(1,766)	(1,574)	(876)
Increase (decrease) in consolidated gross margins	(1,978)	(776)	254
Percentage increase (decrease) in regulated volumes			
Gas sales	(5)	3	1
On-system transportation	(18)	(11)	(8)
Off-system transportation	(15)	—	6
Percentage decrease in non-regulated gas sales volumes	(23)	(15)	(8)

Heating degree days were 99%, 101% and 101% of normal thirty year average temperatures for the three, nine and twelve months ended March 31, 2009, respectively, as compared with 102%, 95% and 95% of normal temperatures in the 2008 periods. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended March 31, 2009, consolidated gross margins decreased $1,978,000 (13%) due to decreased regulated and non-regulated gross margins of $212,000 (2%) and $1,766,000 (37%), respectively. Our non-regulated margins decreased $1,766,000 (37%) due to a 23% decrease in volumes sold and lower sales prices. The non-regulated volumes decreased due to a decrease in our non-regulated customers' gas requirements.

For the nine months ended March 31, 2009, consolidated gross margins decreased $776,000 (3%) due to decreased non-regulated gross margins of $1,574,000 (18%) offset by increased regulated gross margins of $798,000 (4%). Our non-regulated gross margins decreased $1,574,000 (18%) due to a 15% decrease in volumes sold attributable to a decrease in our non-regulated customers' gas requirements. Our regulated gross margin for gas sales increased $556,000 (3%) due to a 3% increase in volumes sold due to colder than normal weather.

For the twelve months ended March 31, 2009, consolidated gross margins increased $254,000 (1%) due to increased regulated gross margins of $1,130,000 (5%) offset by decreased non-regulated gross margins of $876,000 (8%). Our regulated gross margin for gas sales increased $775,000 (4%) due to increased base rates which became effective October 20, 2007. Our regulated off-system transportation margins increased $185,000 (5%) due to a 6% increase in volumes transported. Our non-regulated gross margin for gas sales decreased $865,000 (9%) due to an 8% decrease in volumes sold.

Operations and Maintenance

For the nine months ended March 31, 2009, operations and maintenance expense increased $1,845,000 (19%). The increase was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 12 of the Notes to Consolidated Financial Statements), increased uncollectible expense ($397,000) and increased employee benefit expense ($286,000).

For the twelve months ended March 31, 2009, operations and maintenance expense increased $3,083,000 (24%). The increase was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 12 of the Notes to Consolidated Financial Statements), increased uncollectible expense ($677,000), increased employee benefit expense ($372,000) and increased labor expense ($194,000).

Depreciation and Amortization

For the nine and twelve months ended March 31, 2009, depreciation and amortization decreased $355,000 (11%) and $686,000 (15%), respectively. The decreases were due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decreases were partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Income and Deductions, Net

For the nine and twelve months ended March 31, 2009, other income and deductions, net decreased $136,000 (378%) and $161,000 (149%), respectively. The decreases were due to decreases in the cash surrender value of officers' life insurance as well as decreases in the fair value of the supplementation retirement plan. The decreases in the fair value of the supplemental retirement plan were offset by reductions in operating expenses resulting from corresponding decreases in the liability of the plan.

Income Tax Expense

For the three, nine and twelve months ended March 31, 2009, income tax expense decreased $728,000 (22%), $866,000 (20%) and $690,000 (17%), respectively, as a result of decreased net income before income taxes.

Basic and Diluted Earnings Per Common Share

For the three, nine and twelve months ended March 31, 2009 and 2008, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement of Financial Accounting Standards No. 133, entitled Accounting for Derivative Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly

London Interbank Offered Rate. The balances on our bank line of credit were $10,658,000, $6,829,000 and $3,287,000 on March 31, 2009, June 30, 2008 and March 31, 2008, respectively. The weighted average interest rates on our bank line of credit were 1.24%, 3.2% and 3.86% on March 31, 2009, June 30, 2008 and March 31, 2008, respectively. Based on the amounts of our outstanding bank line of credit on March 31, 2009, June 30, 2008 and March 31, 2008, a one percent (one hundred basis point) increase in our average interest rates would result in decreases in our annual pre-tax net income of $107,000, $68,000 and $33,000, respectively.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported within the time periods specified by the Securities and Exchange Commission's ("SEC's") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of the design and operations of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of March 31, 2009, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended March 31, 2009 and found no changes that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: May 6, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending March 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: May 6, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and
Secretary

Exhibit 32.1

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending March 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that based on my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: May 6, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: May 6, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: May 6, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934

June 30, 2009

Date of Report (Date of earliest event reported)

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	0-8788	61-0458329
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	(Zip Code)

859-744-6171

Registrant's telephone number, including area code

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 1.01 Entry into a Material Definitive Agreement.

Effective June 30, 2009, Delta Natural Gas Company, Inc. entered into a Modification Agreement with Branch Banking and Trust Company which amends the Company's bank line of credit under the original Promissory Note and Addendum dated as of October 31, 2002 and subsequently modified as of October 31, 2003, October 31, 2004, August 12, 2005 and August 31, 2007.

Pursuant to the June 30, 2009 Modification Agreement, the scheduled termination date of the bank line of credit was extended to June 30, 2011. The aggregate principal amount the Company may borrow under the bank line of credit remains at $40,000,000. The interest on this line is determined monthly at the London Interbank Offered Rate plus 1.50% on the used bank line of credit. The annual cost of the unused bank line of credit is .125%.

Except as provided in the Modification Agreement, all of the terms of the Promissory Note and Addendum remain in full force and effect. The foregoing description of the Modification Agreement is a summary and is qualified in its entirety by reference to the Modification Agreement attached hereto as Exhibit 10(a), which is incorporated herein by reference to this Item 1.01.

Item 2.03 Creation of a Direct Financial Obligation or an Obligation Under an Off-Balance Sheet Arrangement of a Registrant.

The information set forth in Item 1.01 of this Current Report on Form 8-K is incorporated into this Item 2.03 by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description
10(a)	Modification Agreement dated June 30, 2009 extending to June 30, 2011 the Promissory Note and Loan Agreement between the Registrant and Branch Banking and Trust Company.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

DELTA NATURAL GAS COMPANY, INC.

Date: June 30, 2009

By: /s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Maker DELTA NATURAL GAS COMPANY, INC.

Address 3617 LEXINGTON RD.
WINCHESTER, KY 40391-0000

BB&T

MODIFICATION AGREEMENT

9580219605
Customer Number

00003
Note Number

$ 40,000,000.00	10/31/2002	$40,000,000.00	6/30/2009
Original Amount of Note	Original Date	Modification Amount	Modification Date

This Modification Agreement (hereinafter "Agreement") is made and entered into this 30th day of June, 2009, by and between DELTA NATURAL GAS COMPANY, INC., maker(s), co-maker(s), endorser(s), or other obligor(s) on the Promissory Note (as defined below), hereinafter also referred to as "Borrower"; and Branch Banking and Trust Company, a North Carolina banking corporation, hereinafter referred to as "Bank".

Witnesseth: Whereas, Borrower has executed and delivered to Bank the following documents (collectively, the "Loan Documents"):

(a) a Promissory Note payable to Bank, which Promissory Note includes the original Promissory Note and Addendum dated as of October 31, 2002, in the face principal amount of $40,000,000.00 and all renewals, extensions, substitutions and modifications thereof, including without limitation the Modification Agreement dated October 31, 2003, the Modification Agreement dated October 31, 2004: the Modification Agreement dated August 12, 2005; and the Modification Agreement dated October 31, 2007, collectively "Promissory Note", said Promissory Note being more particularly identified by description of the original note above;

(b) a Loan Agreement dated October 31, 2002 (hereinafter "Loan Agreement"); and

Borrower and Bank agree that said Loan Documents be modified only to the limited extent as is hereinafter set forth; that all other terms, conditions, and covenants of the Loan Documents remain in full force and effect, and that all other obligations and covenants of Borrower, except as herein modified, shall remain in full force and effect, and binding between Borrower and Bank;

NOW THEREFORE, in mutual consideration of the premises, the sum of Ten Dollars ($10) and other good and valuable consideration, each to the other parties paid, the parties hereto agree that

1. The Promissory Note is amended as hereinafter described:

INTEREST RATE, PRINCIPAL AND INTEREST PAYMENT TERM MODIFICATIONS (To the extent no change is made, existing terms continue. Sections not completed are deleted)

a **Principal and interest are payable as follows:**

☒ Principal (plus any accrued interest not otherwise scheduled herein) is due in full at maturity on 6/30/2011.

☒ Accrued interest is payable Monthly continuing on July 31, 2009 and on the same day of each calendar period thereafter, with one final payment of all remaining interest due on June 30, 2011.

b. The eighth grammatical paragraph on page 1 of the Promissory Note is hereby amended and restated so as to read in its entirety as follows: "This note ('Note') is given by the Borrower in connection with a Loan Agreement between the Borrower and the Bank dated October 31, 2002 (as amended by that certain Modification Agreement between the Bank and the Borrower dated October 31, 2003; that certain Modification Agreement between the Bank and the Borrower dated October 31, 2004; that certain Modification Agreement between the Bank and the Borrower dated August 12, 2005; that certain Modification Agreement between the Bank and the Borrower dated October 31, 2007; and that certain Modification Agreement between Bank and the Borrower dated June 30, 2009) all as executed by the Borrower."

2. The Addendum to Promissory Note is amended as hereinafter described:

The definition of "Adjusted LIBOR Rate" is hereby amended and restated so as to read in its entirety as follows: "Adjusted LIBOR Rate means a rate of interest per annum equal to the sum obtained (rounded upwards, if necessary, to the next higher 1/100th of 1.0%) by adding (i) 30-day LIBOR plus (ii) 1.50 percent (1.50%) per annum, which shall be adjusted monthly on the first day of each month for each LIBOR Interest Period. If the first day of any month falls on date when the Bank is closed, the Adjusted LIBOR Rate shall be determined as of the last preceding business day. The Adjusted LIBOR Rate shall be adjusted for any change in the LIBOR Reserve Percentage so that Bank shall receive the same yield."

3. The Loan Agreement is amended as hereinafter described:

In the paragraph on page 1 of the Loan Agreement, titled "Line of Credit", the date "October 31, 2003" is hereby deleted and the date "June 30, 2011" is inserted in lieu thereof.

If the Promissory Note and Loan Agreement being modified by this Agreement is signed by more than one person or entity, the modified Promissory Note shall be the joint and several obligation of all signers and the property and liability of each and all of them. It is expressly understood and agreed that this Agreement is a modification only and not a novation. The original obligation of the Borrower as evidenced by the Promissory Note above described is not extinguished hereby. It is also understood and agreed that except for the modification(s) contained herein said Promissory Note, and any other Loan Documents or Agreements evidencing, securing or relating to the Promissory Note and all singular terms and conditions thereof, shall be and remain in full force and effect. This Agreement shall not release or affect the liability of any co-makers, obligors, endorsers or guarantors of said Promissory Note. Borrower and Debtor(s)/Grantor(s), if any, jointly and severally consent to the terms of this Agreement, waive any objection thereto, affirm any and all obligations to Bank and certify that there are no defenses or offsets against said obligations or the Bank, including without limitation the Promissory Note. Bank expressly reserves all rights as to any party with right of recourse on the aforesaid Promissory Note.

Borrower agrees that the only interest charge is the interest actually stated in the Promissory Note, and that any loan or origination fee shall be deemed charges rather than interest, which charges are fully earned and non-refundable. It is further agreed that any late charges are not a charge for the use of money but are imposed to compensate Bank for some of the administrative services, costs and losses associated with any delinquency or default under the Promissory Note, and said charges shall be fully earned and non-refundable when accrued. All other charges imposed by Bank upon Borrower in connection with the Promissory Note and the loan including, without limitation, any commitment fees, loan fees, facility fees, origination fees, discount points, default and late charges, prepayment fees, statutory attorneys' fees and reimbursements for costs and expenses paid by Bank to third parties or for damages incurred by Bank are and shall be deemed to be charges made to compensate Bank for underwriting and administrative services and costs, other services, and costs or losses incurred and to be incurred by Bank in connection with the Promissory Note and the loan and shall under no circumstances be deemed to be charges for the use of money. All such charges shall be fully earned and non-refundable when due.

The Bank may, at its option, charge any fees for the modification, renewal, extension, or amendment of any of the terms of the Promissory Note(s) as permitted by applicable law.

In the words "Prime Rate", "Bank Prime Rate", "BB&T Prime Rate", "Bank's Prime Rate" or "BB&T's Prime Rate" are used in this Agreement, they shall refer to the rate announced by the Bank from time to time as its Prime Rate. The Bank makes loans both above and below the Prime Rate and uses indexes other than the Prime Rate. Prime Rate is the name given a rate index used by the Bank and does not in itself constitute a representation of any preferred rate or treatment.

Unless otherwise provided herein, it is expressly understood and agreed by and between Borrower. Debtor(s)/Grantor(s) and Bank that any and all collateral (including but not limited to real property, personal property, fixtures, inventory, accounts, instruments, general intangibles, documents, chattel paper, and equipment) given as security to insure faithful performance by Borrower and any other third party of any and all obligations to Bank, however created, whether now existing or hereafter arising, shall remain as security for the Promissory Note as modified hereby.

It is understood and agreed that if Bank has released collateral herein, it shall not be required or obligated to take any further steps to release said collateral from any lien or security interest unless Bank determines, in its sole discretion, that it may do so without consequence to its secured position and relative priority in other collateral; and unless Borrower bears the reasonable cost of such action. No delay or omission on the part of the Bank in exercising any right hereunder shall operate as a waiver of such right or of any other right of the Bank, nor shall any delay, omission or waiver on any one occasion be deemed a bar to or waiver of the same, or of any other right on any further occasion. Each of the parties signing this Agreement regardless of the time, order or place of signing waives presentment, demand, protest, and notices of every kind, and assents to any one or more extensions or postponements of the time of payment or any other indulgences, to any substitutions, exchanges or releases of collateral if at any time there is available to the Bank collateral for the Promissory Note, as amended, and to the additions or releases of any other parties or persons primarily or secondarily liable. Whenever possible the provisions of this Agreement shall be interpreted in such manner as to be effective and valid under applicable law, but if any provision of this Agreement is prohibited by or invalid under such law, such provisions shall be ineffective to the extent of any such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Agreement. All rights and obligations arising hereunder shall be governed by and construed in accordance with the laws of the same state which governs the interpretation and enforcement of the Promissory Note.

From and after any event of default under this Agreement, the Promissory Note, or any related deed of trust, security agreement or loan agreement, interest shall accrue on the sum of the principal balance and accrued interest then outstanding at the variable rate equal to the Bank's Prime Rate plus 5% per annum ("Default Rate"), provided that such rate shall not exceed at any time the highest rate of interest permitted by the laws of the Commonwealth of Kentucky; and further that such rate shall apply after judgement. In the event of any default, the then remaining unpaid principal amount and accrued but unpaid interest then outstanding shall bear interest at the Default Rate until such principal and interest have been paid in full. Bank shall not be obligated to accept any check, money order, or other payment instrument marked "payment in full" on any disputed amount due hereunder, and Bank expressly reserves the right to reject all such payment instruments. Borrower agrees that tender of its check or other payment instrument so marked will not satisfy or discharge its obligation under this Note, disputed or otherwise, even if such check or payment instrument is inadvertently processed by Bank unless in fact such payment is in fact sufficient to pay the amount due hereunder.

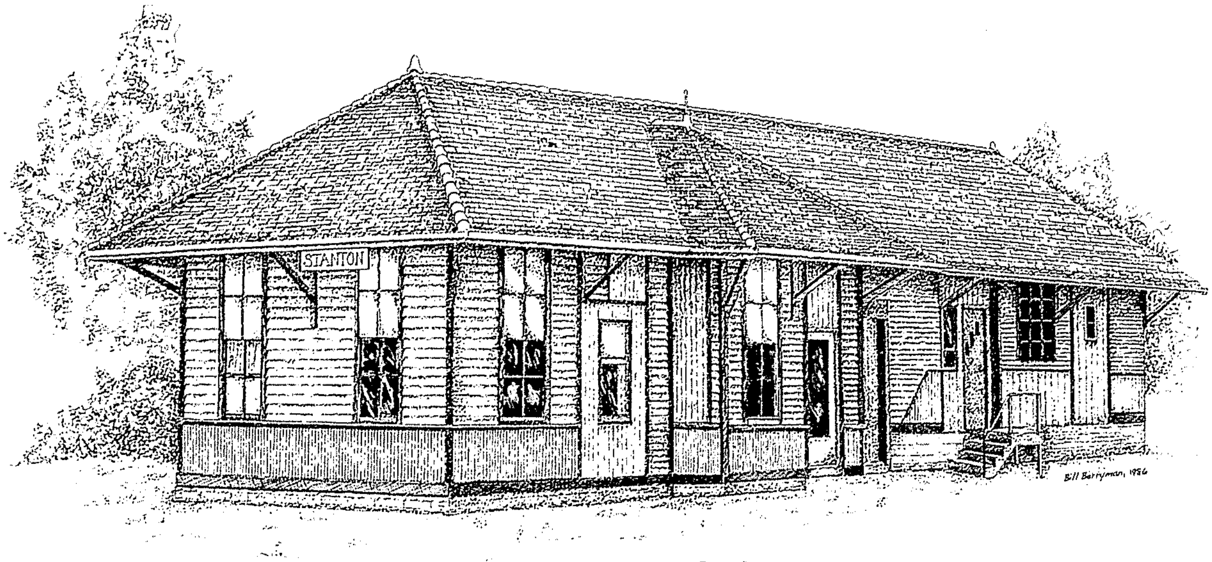
DELTA NATURAL GAS COMPANY, INC.

By /s/Glenn R. Jennings
Glenn R. Jennings, President

BRANCH BANKING AND TRUST COMPANY

By /s/W. Harvey Coggin
W. Harvey Coggin, Senior Vice President

Delta Natural Gas Company, Inc.



Birth Place of Delta Natural Gas Co.
October 10, 1949

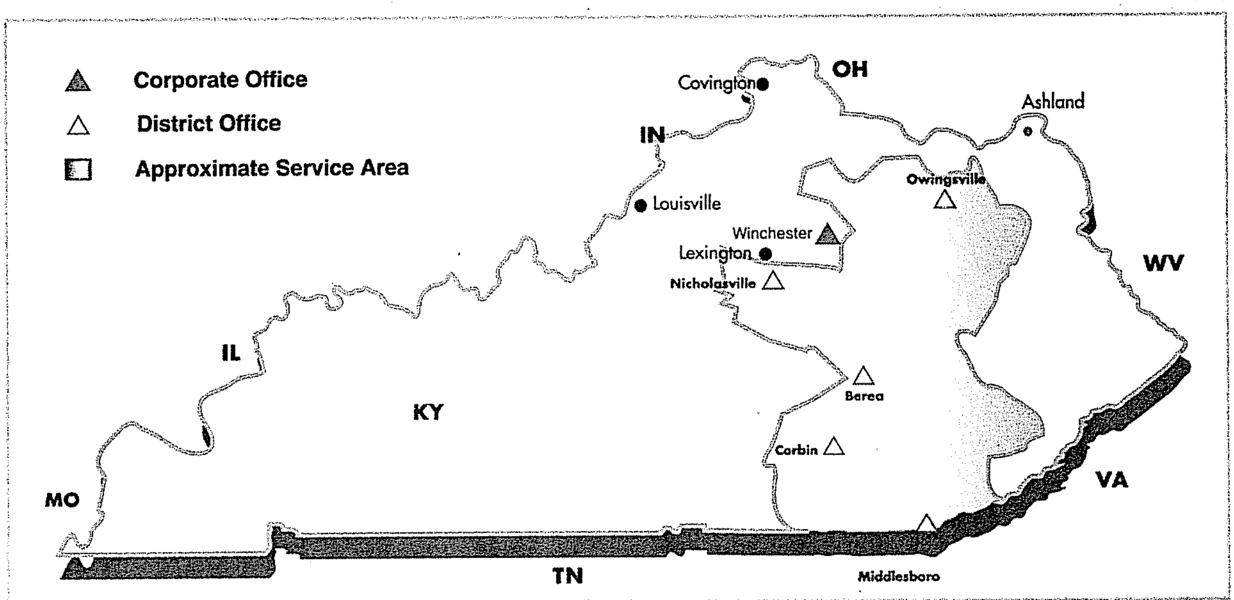
Quality Service for 60 Years ...

2009

Annual Report

Our Mission Statement

Delta will provide premier natural gas services while having a positive impact on customers, employees and shareholders.



To Our Shareholders

Few, if any, can deny that we are living in turbulent, changing times. We have witnessed much in fiscal 2009, including a significant drop in the stock market, increasing unemployment, turmoil in the economy, and volatility specifically in banking, insurance and automotive sectors, to name a few. Financial stress on individuals and businesses around the globe has steadily increased.

Through all of this in the past year, Delta has fared reasonably well overall. Despite reduced earnings from our non-regulated operations, coupled with a storage inventory adjustment, our 2009 earnings per share were $1.58, with a dividend paid of $1.28 per share. Based upon stock prices over this past year, this provided a cash yield to our investors in the 5%-6% range. Our stock price has been somewhat volatile, but not as much as the market as a whole.

Our total throughput exceeded 19 billion cubic feet in 2009. Fiscal 2009 included a full year under the new base rates from our 2007 rate case, and our regulated segment reflects this. Although our non-regulated segment results declined this year, those businesses continued to contribute favorably to our overall results in 2009.

A global as well as more local effort for carbon constraints has led to a continuing and growing green focus in Kentucky. We view natural gas as part of the solution in this, as well as a way to strengthen our national and state energy postures and lessen our dependence on other traditional energy sources. Working with the Kentucky Public Service Commission and the Kentucky Attorney General, we developed a demand side management program that was implemented in 2009 to better align Delta's and our customers' interests. We can now better promote conservation and efficiency improvements by our customers without being penalized as much financially. Rate design changes from our last rate case helped to partially decouple our revenues from sales volumes by increasing our monthly customer charge instead of our volumetric rates.

A significant strength of our Company, which complements our 2,500 miles of pipelines in 23 Kentucky counties, is our people. I want to acknowledge all of our hard working, dedicated employees. I thank each of them for all they do each day to provide top quality service in all of Delta's operations. Their willingness to tackle any situation is a constant source of inspiration.

Delta was started 60 years ago by Harrison D. Peet. His vision, strength and determination have made Delta what it is, and he and all the others who helped as Delta grew and developed are very much thanked and recognized. Hopefully, we can continue their efforts and provide for the Company's continued success.

During 2009, Alan Heath retired as Delta's Vice President-Operations and Engineering. Alan served the Company well since 1984, and we thank him for his dedicated service and for all he helped accomplish at Delta. Also, Clyde Russell retired during 2009 as Delta's Manager-Transmission. Working at Delta since 1975, Clyde was a tremendous benefit to the Company in many ways and his efforts are greatly appreciated. I extend our sincere thanks and very best wishes to both.

Brian Ramsey was promoted to the position of Vice President-Transmission and Gas Supply during 2009. Brian has worked for Delta since 1984 and we look forward to his continuing involvement in his new and important role.

Also, Johnny Caudill was named Vice President-Distribution during 2009. Johnny has been with Delta since 1972, and he has served as an officer since 1995. He has contributed significantly to Delta's success and will continue to do so in his expanded role at the company.

Reflecting its optimistic outlook for the future of Delta, your Board of Directors, at its meeting on August 21, 2009, increased the dividend on the Company's common stock to $1.30 per share on an annual basis. We hope you share in their enthusiasm for Delta's future prospects.

Thank you for your continuing support of the Company.

Sincerely,

Glenn R. Jennings

Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

August 24, 2009

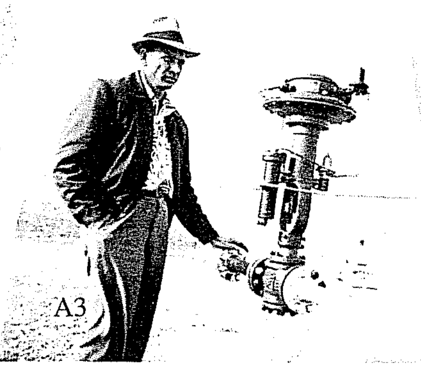
Delta was incorporated on October 10, 1949, with its management and stockholders being Harrison D. Peet, President; Virgil E. Scott, Secretary-Treasurer, Harry Peet, Jr., Vice President and John D. Harrison, Construction Supervisor. Delta was an outgrowth of Power Line Construction Company. On October 13, 1949, Delta, headquartered in Stanton, Kentucky at that time, successfully acquired its first franchise to supply the city of Owingsville, Kentucky, with gas. Delta's headquarters were relocated to Owingsville in 1951.

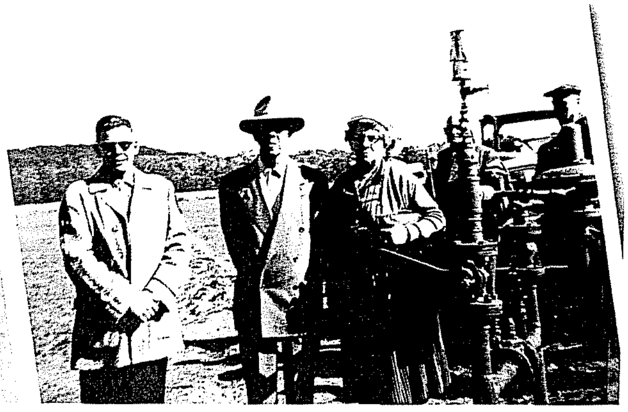
Delta continued to grow by expanding into new areas. Delta built transmission lines to the interstate pipelines and supplied local communities that had, prior to that time, been without natural gas service. Delta identified communities for expansion and continued to build facilities and add new customers. The Berea system was added in 1955, and the Nicholasville and Wilmore systems were added in 1956. Delta continued to rapidly add customers in the latter 1950's including the addition by purchase of the Stanton system.

Delta had grown by 1977 to approximately 11,000 customers and 300 miles of pipeline. Annual throughput volumes were 2.2 billion cubic feet with total revenues of $4.8 million. Delta had its corporate office in Winchester, Kentucky. In October, 1977, Delta acquired Gas Service Company, Inc., Cumberland Valley Pipe Line Co. and Laurel Valley Pipe Line Company. These companies were engaged in natural gas distribution and transmission, and some limited production activities, in southeastern Kentucky and served approximately 8,500 customers in Barbourville, London, Middlesboro, Pineville and Williamsburg.

> **"Delta Gas has a great vision in new work being done, not only for the employee but also for the customer. Delta cares about how the project looks and impacts the land and community."**
>
> Ruben York
>
> Equipment Operator

After these three acquisitions, the Company built its present corporate office during 1978 in Winchester and relocated there from former leased space in The Winchester Bank. The stock sales to finance these acquisitions increased the number of shareholders to a





"Through the years Delta Natural Gas has remained true to what the company was founded on, the commitment to good service through discipline, dedication and compassion to both our customers, the employee and their families. I have great confidence in this company and look forward to the future as a Delta Natural Gas employee."

Kathy Becraft
Accounting Financial Analyst

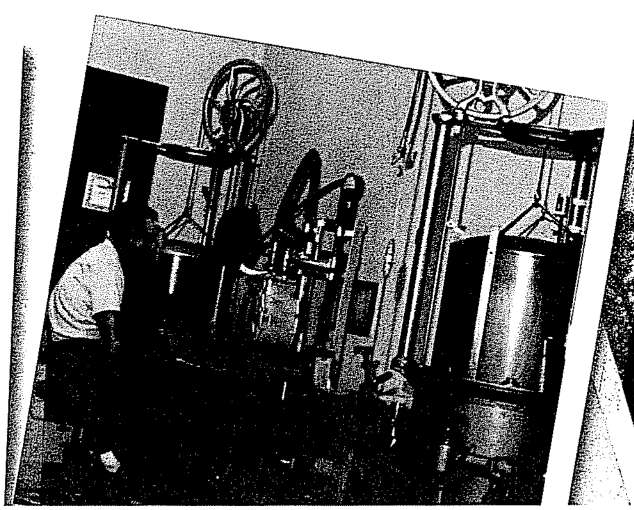
point where Delta's common stock was registered under the Securities Exchange Act in latter 1978.

By 1980, annual throughput volumes were 4 billion cubic feet, with revenues of $14.3 million. The mix of gas supply had also changed, from 100% supplied by interstate pipelines in 1977 to only 53% in 1980. Delta's total number of employees had grown to 105 by 1980. Delta continued to acquire natural gas produced locally in southeastern Kentucky and also continued to pursue other gas system acquisitions. In January, 1981, Peoples Gas Company of Kentucky was acquired. This added approximately 8,700 customers to Delta's system.

In order to finance this growth, in April, 1981, Delta sold 500,000 shares of common stock in its first registered offering and, since that time, its common stock has been traded on the NASDAQ under the symbol DGAS. Dividends on common stock were begun in 1964 and have continued since then. Dividends have been increased gradually to their present annualized level of $1.28 per share.

Delta has continued to expand into gathering and transporting gas for producers and others, including developing an underground storage field in 1996. Delta's facilities include over 2,500 miles of distribution and transmission pipelines, gathering and compression facilities. Delta's three non-regulated subsidiary companies, which buy, sell and produce natural gas, have contributed increasingly to Delta's financial results.

Delta has grown to a system of approximately 37,000 customers with 155 employees and 5 district operations offices and the Winchester corporate office. Total throughput volumes exceeded 19 billion cubic feet in 2009, with revenues in excess of $105 million.



Selected Financial Information

For the Years Ended June 30,	**2009**	2008	2007	2006	2005
Summary of Operations ($)					
Operating revenues (a)(b)	**105,636,824**	112,657,117	98,168,391	117,247,144	84,181,233
Operating income (a)(b)(c)	**12,793,200**	15,663,736	12,968,043	12,757,507	12,490,127
Net income (a)(b)(c)	**5,210,729**	6,829,868	5,298,347	5,024,635	4,998,619
Basic and diluted earnings per common share (a)(b)(c)	**1.58**	2.08	1.62	1.55	1.55
Dividends declared per common share	**1.28**	1.24	1.22	1.20	1.18
Total Assets ($)	**162,505,295**	170,814,856	160,400,950	155,554,125	144,762,217
Capitalization ($)					
Common shareholders' equity	**58,999,182**	57,593,585	54,428,471	52,609,724	50,799,454
Long-term debt (d)	**57,599,000**	58,318,000	58,625,000	58,790,000	52,707,000
Total capitalization	**116,598,182**	115,911,585	113,053,471	111,399,724	103,506,454
Short-Term Debt ($) (d)(e)	**4,853,103**	8,028,791	5,389,918	8,246,434	7,609,122
Capital Expenditures	**8,422,433**	5,563,667	8,082,918	7,781,396	5,338,356

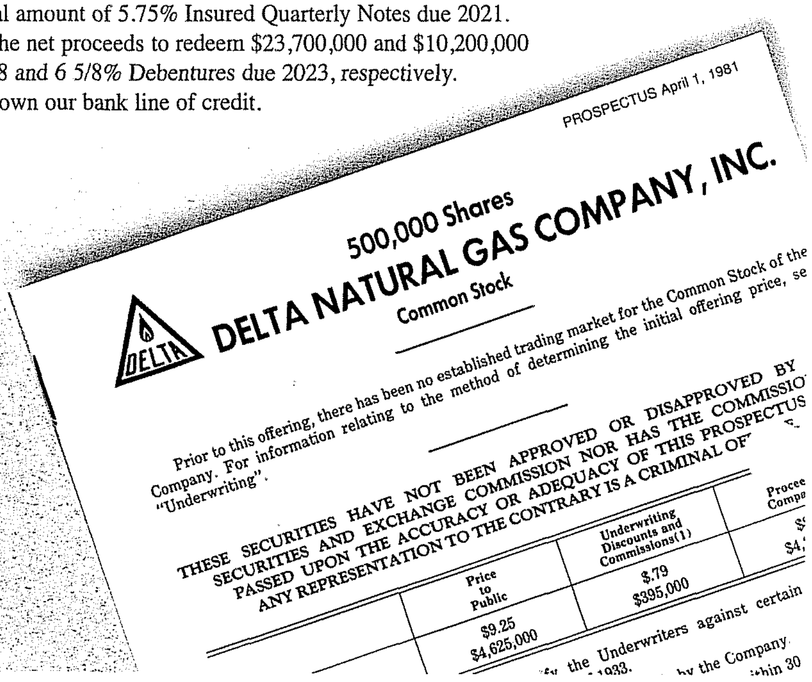
(a) We recorded 58,000 Mcf of unbilled sales at June 30, 2005, resulting in non-recurring increases of $1,246,000 in operating revenues, $617,000 in operating income, $379,000 in net income and $.12 in basic and diluted earnings per common share for fiscal 2005.

(b) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and the rates were designed to generate additional annual revenue of $3,920,000.

(c) We recorded a $1,350,000 non-recurring inventory adjustment at December 31, 2008 for our gas in storage, as discussed in Note 15 of the Notes to Consolidated Financial Statements in Item 8.

(d) During April, 2006, we issued $40,000,000 aggregate principal amount of 5.75% Insured Quarterly Notes due 2021. The net proceeds of the offering were $37,671,000. We used the net proceeds to redeem $23,700,000 and $10,200,000 aggregate principal amount of our 7.15% Debentures due 2018 and 6 5/8% Debentures due 2023, respectively. The remaining net proceeds of $3,830,000 were used to pay down our bank line of credit.

(e) Includes current portion of long-term debt.


PROSPECTUS April 1, 1981

500,000 Shares

DELTA NATURAL GAS COMPANY, INC.

Common Stock

Prior to this offering, there has been no established trading market for the Common Stock of the Company. For information relating to the method of determining the initial offering price, se "Underwriting".

THESE SECURITIES HAVE NOT BEEN APPROVED OR DISAPPROVED BY SECURITIES AND EXCHANGE COMMISSION NOR HAS THE COMMISSIO PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OF

	Price to Public	Underwriting Discounts and Commissions(1)	Proce Compa
	$9.25	$.79	$
	$4,625,000	$395,000	$4,

the Underwriters against certain 1933. by the Company. ithin 30

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

(Mark one)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended June 30, 2009

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______ to ________
Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of principal executive offices)	40391 (Zip code)

859-744-6171
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $1 Par Value	NASDAQ OMX Group

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15 (d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recent completed second fiscal quarter. $80,205,566

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. As of August 15, 2009, Delta Natural Gas Company, Inc. had outstanding 3,319,374 shares of common stock $1 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive proxy statement, to be filed with the Commission not later than 120 days after June 30, 2009, is incorporated by reference in Part III of this Report.

TABLE OF CONTENTS

PART I

Item 1. Business

General

We distribute or transport natural gas to approximately 37,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We produce a relatively small amount of natural gas from our southeastern Kentucky wells.

We seek to provide dependable, high-quality service to our customers while steadily enhancing value for our shareholders. Our efforts have been focused on developing a balance of regulated and non-regulated businesses to contribute to our earnings by profitably producing, selling and transporting natural gas in our service territory.

We strive to achieve operational excellence through economical, reliable service and our emphasis on responsiveness to customers. We continue to invest in facilities for the transmission, distribution and storage of natural gas. We believe that our responsiveness to customers and the dependability of the service we provide afford us additional opportunities for growth. While we seek those opportunities, our strategy will continue a conservative approach that seeks to minimize our exposure to market risk arising from fluctuations in the prices of gas.

We operate through two segments, a regulated segment and a non-regulated segment. See Note 14 of the Notes to Consolidated Financial Statements, in Item 8. Financial Statements and Supplementary Data, for a discussion of these segments.

Our executive offices are located at 3617 Lexington Road, Winchester, Kentucky 40391. Our telephone number is (859) 744-6171. Our website is www.deltagas.com.

Regulated Operations

Distribution and Transportation

Through our regulated segment, we distribute natural gas to our retail customers in 23 predominantly rural counties. In addition, our regulated segment transports gas to industrial customers on our system who purchase gas in the open market. Our regulated segment also transports gas on behalf of local producers and other customers not on our distribution system.

The economy of our service area is based principally on coal mining, farming and light industry. The communities we serve typically contain populations of less than 20,000. Our three largest service areas are Nicholasville, Corbin and Berea, Kentucky. In Nicholasville we serve approximately 8,000 customers, in Corbin we serve approximately 6,000 customers, and in Berea we serve approximately 4,000 customers. Some of the communities we serve continue to expand, resulting in growth opportunities for us. Industrial parks have been developed in our service areas, which could result in additional growth in industrial customers as well.

The Kentucky Public Service Commission exercises regulatory authority over our regulated natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers.

Factors that affect our regulated revenues include rates we charge our customers, our supply cost for the natural gas we purchase for resale, economic conditions in our service areas, weather and competition.

Our results of operations and financial condition have been strengthened by regulatory developments in recent years, including a $3,920,000 annual revenue increase from our last rate case in 2007, a weather normalization provision in our tariff, which has reduced fluctuations in our earnings due to variations in weather, and a gas cost recovery clause, which mitigates market risk arising from fluctuations in the price of gas.

Although the Kentucky Public Service Commission permits us to pass through to our regulated customers changes in the price we must pay for our gas supply through our gas cost recovery clause, increases in our rates to customers may cause our customers to conserve or to use alternative energy sources.

Our regulated sales are seasonal and temperature-sensitive, since the majority of the gas we sell is used for heating. During 2009, 73% of the regulated volumes were sold during the heating season (December through April). Variations in the average temperature during the winter impact our revenues year-to-year. The Kentucky Public Service Commission, through a weather normalization provision in our tariff, permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

We compete with alternate sources of energy for our regulated distribution customers. These alternate sources include electricity, coal, oil, propane and wood. Our non-regulated subsidiaries, which sell gas to industrial customers and others, compete with natural gas producers and natural gas marketers for those customers.

Our larger regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supplies would be most likely to consider taking this action. Additionally, some of our industrial customers are able to switch economically to alternative sources of energy. These are competitive concerns that we continue to address by utilizing our non-regulated segment to offer these customers gas supply at competitive market based rates.

Some natural gas producers in our service area can access pipeline delivery systems other than ours, which generates competition for our transportation services. We continue our efforts to purchase or transport natural gas that is produced in reasonable proximity to our transportation facilities through our regulated segment.

As an active participant in many areas of the natural gas industry, we plan to continue efforts to expand our gas distribution system and customer base. We continue to consider acquisitions of other gas systems, some of which are contiguous to our existing service areas, as well as expansion within our existing service areas.

Gas Supply

We purchase our natural gas from a combination of interstate and Kentucky sources. In our fiscal year ended June 30, 2009, we purchased approximately 99% of our natural gas from interstate sources.

Interstate Gas Supply

Our regulated segment acquires its interstate gas supply from gas marketers. We currently have commodity requirements agreements with Atmos Energy Marketing ("Atmos") for our Columbia Gas Transmission Corporation ("Columbia Gas"), Columbia Gulf Transmission Corporation ("Columbia Gulf"), Tennessee Gas Pipeline ("Tennessee") and Texas Eastern Transmission Corporation ("Texas Eastern") supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. The gas we purchase under these agreements is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. The index-based market prices are determined based on the prices published on the first of the month in Platts' Inside FERC's Gas Market Report in the indices that relate to the pipelines through which the gas will be transported, plus or minus an agreed-to fixed price adjustment per million British Thermal Units of gas purchased. Consequently, the price we pay for interstate gas is based on current market prices.

Our agreements with Atmos for the Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied service areas continue year to year unless cancelled by either party by written notice at least sixty days prior to the annual anniversary date (April 30) of the agreement. In our fiscal year ended June 30, 2009, approximately 48% of our regulated gas supply was purchased under our agreements with Atmos.

Our regulated segment purchases gas from M & B Gas Services, Inc. ("M & B") for injection into our underground natural gas storage field and to supply a portion of our system. We are not obligated to purchase any minimum quantities from M & B nor to purchase gas from M & B for any periods longer than one month at a time. The gas is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. Our agreement with M & B may be terminated upon 30 days prior written notice by either party. In our fiscal year ended June 30, 2009, approximately 51% of our regulated gas supply was purchased under our agreement with M & B.

We also purchase interstate natural gas from other gas marketers as needed at either current market prices, determined by industry publications, or at forward market prices.

Transportation of Interstate Gas Supply

Our interstate natural gas supply is transported to us from market hubs, production fields and storage fields by Tennessee, Columbia Gas, Columbia Gulf and Texas Eastern.

Our agreements with Tennessee extend through 2013 and thereafter automatically renew for subsequent five-year terms unless terminated by one of the parties. Tennessee is obligated under these agreements to transport up to 19,600 thousand cubic feet ("Mcf") per day for us. During fiscal 2009, Tennessee transported a total of 1,080,000 Mcf for us under these contracts. Annually, approximately 31% of our regulated supply requirements flow through Tennessee to our points of receipt under our transportation agreements with Tennessee. We have gas storage agreements with Tennessee under the terms of which we reserve a defined storage space in Tennessee's storage fields and we reserve the right to withdraw daily gas volumes up to certain specified fixed quantities. These gas storage agreements renew on the same schedule as our transportation agreements with Tennessee.

Under our agreements with Columbia Gas and Columbia Gulf, Columbia Gas is obligated to transport, including utilization of our defined storage space as required, up to 12,600 Mcf per day for us, and Columbia Gulf is obligated to transport up to a total of 4,300 Mcf per day for us. During fiscal 2009 Columbia Gas and Columbia Gulf transported for us a total of 563,000 Mcf, or approximately 16% of our regulated supply requirements, under all of our agreements with them. All of our transportation agreements with Columbia Gas and Columbia Gulf continue on a year-to-year basis until terminated by one of the parties.

Columbia Gulf also transported additional volumes under agreements it has with M & B to a point of interconnection between Columbia Gulf and us where we purchase the gas to inject into our storage field. The amounts transported and sold to us under the agreement between Columbia Gulf and M & B for fiscal 2009 constituted approximately 51% of our regulated gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the gas to us that we purchase from Texas Eastern to supply our customers' requirements in specific geographic areas. Consequently, Texas Eastern transports a small percentage of our interstate gas supply. In our fiscal year ended June 30, 2009, Texas Eastern transported approximately 17,000 Mcf of natural gas to our system, which constituted less than 1% of our gas supply.

Kentucky Gas Supply

We have an agreement with Chesapeake Appalachia LLC ("Chesapeake") to purchase natural gas on a year-to-year basis unless terminated by one of the parties. We purchased 43,000 Mcf from Chesapeake during fiscal 2009. The price for the gas we purchase from Chesapeake is based on the index price of spot gas delivered to Columbia Gas in the relevant region as reported in Platt's Inside FERC's Gas Market Report, plus a fixed adjustment per million British Thermal units of gas purchased. Chesapeake delivers this gas to our customers directly from its own pipelines.

We own and operate an underground natural gas storage field that we use to store a significant portion of our winter gas supply needs. This storage capability permits us to purchase and store gas during the non-heating months and then withdraw and sell the gas during the peak usage months.

We continue to maintain an active gas supply management program that emphasizes long-term reliability and the pursuit of cost-effective sources of gas for our customers.

Regulatory Matters

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge, and therefore the increase in revenue occurred more evenly throughout the year and was not as dependent on customer usage. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customer's interests by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible. Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

Non-Regulated Operations

Marketing and Production

We operate our non-regulated segment through three wholly-owned subsidiaries. Two of these subsidiaries, Delta Resources, Inc. and Delgasco, Inc., purchase natural gas in the open market, including natural gas from Kentucky producers. We resell this gas to industrial customers on our distribution system and to others not on our system. Our third subsidiary, Enpro, Inc., produces natural gas that is sold to Delgasco for resale in the open market.

Factors that affect our non-regulated revenues include rates we charge our customers, our supply cost for the natural gas we purchase for resale, economic conditions in our service areas, weather and competition.

Our larger non-regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Additionally, some of our industrial customers are able to switch economically to alternative sources of energy. We continue to address these competitive concerns by offering these customers gas supply at competitive market based rates.

We anticipate continuing our non-regulated gas production and marketing activities and intend to pursue and increase these activities wherever practicable.

A single customer, Citizens Gas Utility District, provided $10,248,000, $17,087,000 and $9,843,000 of non-regulated revenues during 2009, 2008 and 2007, respectively. Citizens has decreased their purchases from us, and thus revenues are not expected to continue at historical levels.

Gas Supply

Our non-regulated segment purchases gas from M & B Gas Services, Inc. ("M & B"). We are not obligated to purchase any minimum quantities from M & B nor to purchase gas from M & B for any periods longer than one month at a time. The gas is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. Our agreement with M & B may be terminated upon 30 days prior written notice by either party. Any purchase agreements for unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2009, approximately 69% of our non-regulated gas supply was purchased under our agreement with M & B.

Additionally, our non-regulated segment purchases natural gas from Atmos as needed. This spot gas purchasing arrangement is pursuant to an agreement with Atmos containing an "evergreen" clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from Atmos under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing gas for one or more months. The price of gas under this agreement is based on current market prices. In our fiscal year ended June 30, 2009, approximately 29% of our non-regulated gas supply was purchased under our agreement with Atmos.

We also purchase interstate natural gas from other gas marketers and Kentucky producers as needed at either current market prices, determined by industry publications, or at forward market prices.

Capital Expenditures

Capital expenditures during 2009 were $8.4 million and for 2010 are estimated to be $6.3 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are met through the use of internally generated funds and a short-term bank line of credit. The current available line of credit is $40 million, of which $3.7 million was borrowed at June 30, 2009.

Present plans are to continue to utilize the bank line of credit, which extends through June 30, 2011, to meet planned capital expenditures and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

Employees

On June 30, 2009, we had 155 full-time employees. We consider our relationship with our employees to be satisfactory. Our employees are not represented by unions nor are they subject to any collective bargaining agreements.

Available Information

We make available free of charge on our Internet website http://www.deltagas.com, our Business Code of Conduct and Ethics, annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains an internet site http://www.sec.gov that contains reports, proxy and information statements and other information regarding Delta. The public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The SEC's phone number is 1-800-732-0330.

Consolidated Statistics

For the Years Ended June 30,	2009	2008	2007	2006	2005
Average Retail Customers Served					
Residential	**30,881**	31,520	31,941	32,601	33,284
Commercial	**5,009**	5,107	5,128	5,154	5,241
Industrial	**49**	54	59	59	60
Total	**35,939**	36,681	37,128	37,814	38,585
Operating Revenues ($000) (a)					
Residential sales	**33,774**	30,742	28,648	35,240	29,172
Commercial sales	**24,125**	21,171	19,339	24,081	18,029
Industrial sales	**1,769**	1,707	1,676	2,356	1,744
Total regulated sales (b)(c)	**59,668**	53,620	49,663	61,677	48,945
On-system transportation (c)	**4,118**	4,461	4,258	4,371	4,312
Off-system transportation (c)	**3,786**	3,864	2,979	2,543	2,099
Non-regulated sales	**41,147**	54,438	44,669	51,904	31,971
Other	**333**	293	242	250	211
Eliminations for intersegment	**(3,427)**	(4,019)	(3,643)	(3,498)	(3,357)
Total	**105,625**	112,657	98,168	117,247	84,181
System Throughput (Million Cu. Ft.) (a)					
Residential sales	**1,721**	1,695	1,801	1,764	2,018
Commercial sales	**1,346**	1,286	1,345	1,313	1,381
Industrial sales	**113**	121	136	146	158
Total regulated sales (b)	**3,180**	3,102	3,282	3,223	3,557
On-system transportation	**4,215**	4,975	5,161	5,322	5,273
Off-system transportation	**11,908**	12,623	9,774	8,789	7,194
Non-regulated sales	**4,219**	5,394	4,921	4,398	3,924
Eliminations for intersegment	**(4,135)**	(5,276)	(4,822)	(4,313)	(3,831)
Total	**19,387**	20,818	18,316	17,419	16,117
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	**56**	54	56	54	61
Lexington, Kentucky Degree Days					
Actual	**4,651**	4,464	4,419	4,309	4,293
Percent of 30 year average	**101**	96	95	92	92

(a) Additional financial information related to our segments can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 14 of the Notes to Consolidated Financial Statements.

(b) 2005 regulated sales includes a $1,246,000 non-recurring increase in revenues due to the recording of 58,000 Mcf of unbilled sales at June 30, 2005.

(c) We implemented new regulated base rates, as approved by the Kentucky Public Service Commission in October, 2007, which were designed to generate additional annual revenue of $3,920,000.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR. Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 75% of our annual gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, which would reduce our revenues and profits. The weather normalization clause in our rate tariff, approved by the Kentucky Public Service Commission, only partially mitigates this risk. Under our weather normalization clause in our rate tariffs, we adjust our rates to residential and small non-residential customers to reflect variations from thirty-year average weather for our December through April billing cycles.

CHANGES IN FEDERAL REGULATIONS COULD REDUCE THE AVAILABILITY OR INCREASE THE COST OF OUR INTERSTATE GAS SUPPLY. We purchase almost all of our gas supply from interstate sources. For example, in our fiscal year ended June 30, 2009, approximately 99% of our gas supply was purchased from interstate sources. The Federal Energy Regulatory Commission regulates the transmission of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies in a manner that could increase transportation rates or reduce pipeline or storage capacity available to us.

OUR GAS SUPPLY DEPENDS UPON THE AVAILABILITY OF ADEQUATE PIPELINE TRANSPORTATION CAPACITY. We purchase almost all of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of gas.

OUR CUSTOMERS ARE ABLE TO ACQUIRE NATURAL GAS WITHOUT USING OUR DISTRIBUTION SYSTEM. Our larger customers can obtain their natural gas supply by purchasing their natural gas directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers may undertake such a by-pass of our distribution system in order to achieve lower prices for their gas service. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution system creates a risk of the loss of large customers and thus could result in lower revenues and profits.

WE FACE REGULATORY UNCERTAINTY AT THE STATE LEVEL. We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our income from operations. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability.

VOLATILITY IN THE PRICE OF NATURAL GAS COULD REDUCE OUR PROFITS. Significant increases in the price of natural gas will likely cause our regulated retail customers to continue to conserve or switch to alternate sources of energy. Any decrease in the volume of gas we sell that is caused by such actions will reduce our revenues and profits. Higher prices also make it more difficult to add new customers. Significant decreases in the price of natural gas will likely cause our non-regulated segment margins to decrease.

WE DO NOT ALWAYS GENERATE SUFFICIENT CASH FLOWS TO MEET ALL OUR CASH NEEDS. We make capital expenditures in order to maintain, expand and upgrade our distribution and transmission system. As a result, we fund a portion of our cash needs through borrowing and by offering new securities into the market. Although cash needs vary from year to year, our dependence on external sources of financing creates the risks that our profits could decrease as a result of high capital costs and that lenders could impose onerous and unfavorable terms on us as a condition to granting us loans. We also have the risk that we may not be able to secure external sources of cash necessary to fund our operations. In 2009 cash provided by operating activities was sufficient to meet our financing needs, and we were able to make a net repayment on our short-term bank line of credit in the amount of $3,176,000.

INTERSTATE AND OTHER PIPELINES DELTA INTERCONNECTS WITH CAN IMPOSE RESTRICTIONS ON THEIR PIPELINE. The pipelines interconnected to Delta's system are owned and operated by third parties who can impose restrictions on the quantity and quality of natural gas they will accept into their pipelines.

To the extent natural gas on Delta's system does not conform to these restrictions, Delta could experience a decrease in volumes sold or transported to these pipelines.

FUTURE PROFITABILITY OF THE NON-REGULATED SEGMENT IS DEPENDENT ON A FEW INDUSTRIAL AND OTHER LARGE USE CUSTOMERS. Our larger non-regulated customers are primarily industrial and other large use customers. Fluctuations in the gas requirements of these customers can have a significant impact on the profitability of the non-regulated segment. We attempt to mitigate this risk by seeking additional opportunities for our non-regulated segment to sell gas to customers on and off Delta's system.

CURRENT LEVELS OF CAPITAL AND CREDIT MARKET VOLATILITY ARE UNPRECEDENTED. The capital and credit markets have been experiencing extreme volatility and disruption. In recent months, the volatility and disruption have reached unprecedented levels. In some cases, the markets have exerted downward pressure on stock prices and credit availability for certain companies. To the extent that internally generated cash coupled with short-term borrowings under our bank line of credit is not sufficient for our operating cash requirements and normal capital expenditures we may need to obtain additional financing. If current levels of market disruption and volatility continue or worsen, under such extreme market conditions, there can be no assurance other financing sources would be available or sufficient. Additionally, our access to funds under our bank line of credit is dependent on the liquidity of the lender, Branch Banking & Trust Company.

POOR INVESTMENT PERFORMANCE OF PENSION PLAN HOLDINGS AND OTHER FACTORS IMPACTING PENSION PLAN COSTS COULD UNFAVORABLY IMPACT OUR LIQUIDITY AND RESULTS OF OPERATIONS. Our cost of providing a non-contributory defined benefit pension plan is dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and our required or voluntary contributions made to the plan. Due to the conditions in the debt and equity markets, we experienced a decline in the value of the assets held by our defined benefit pension plan and thus we contributed $2,677,000 to the plan in fiscal 2009. Without sustained growth in the pension investments over time to increase the value of the plan assets and depending upon the other factors impacting our costs as listed above, we could be required to fund our plan with additional significant amounts of cash. Such cash funding obligations could have a material impact on our financial position, results of operations or cash flows.

WE ARE EXPOSED TO CREDIT RISK OF CUSTOMERS AND OTHERS WITH WHOM WE DO BUSINESS. Adverse economic conditions affecting, or financial difficulties of, customers and others with whom we do business could impair the ability of these customers and others to pay for our services or fulfill their contractual obligations or cause them to delay such payments or obligations. We depend on these customers and others to remit payments on a timely basis. Any delay or default in payment could adversely affect our cash flows, financial position or results of operations.

SUBSTANTIAL OPERATIONAL RISKS ARE INVOLVED IN OPERATING A NATURAL GAS DISTRIBUTION, PIPELINE AND STORAGE SYSTEM AND SUCH OPERATIONAL RISKS COULD REDUCE OUR REVENUES AND INCREASE EXPENSES. There are substantial risks associated with the operation of a natural gas distribution, pipeline and storage system, such as operational hazards and unforeseen interruptions caused by events beyond our control. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline and storage facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage and environmental pollution, which in turn could lead to substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. Liabilities incurred that are not fully covered by insurance could adversely affect our results of operations and financial condition. Additionally, interruptions to the operation of our gas distribution, transmission or storage system caused by such an event could reduce our revenues and increase our expenses.

HURRICANES OR OTHER EXTREME WEATHER COULD INTERRUPT OUR GAS SUPPLY AND INCREASE NATURAL GAS PRICES. Hurricanes or other extreme weather could damage production or transportation facilities, which could result in decreased supplies of natural gas and increased supply costs for us and higher prices for our customers.

CROSS-DEFAULT PROVISIONS IN OUR BORROWING ARRANGEMENTS INCREASE THE CONSEQUENCES OF A DEFAULT ON OUR PART. Each indenture under which our outstanding debt has been issued, and the loan agreements for our bank line of credit, contains a cross-default provision which provides that we will be in default under such indenture or loan agreement in the event of certain defaults under any of the other indentures or loan agreements. Accordingly, should an event of default occur under one of our debt agreements, we face the prospect of being in default under all of our debt agreements and obliged in such instance to satisfy all of our then-outstanding indebtedness. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us.

OUR BORROWING ARRANGEMENTS INCLUDE VARIOUS NEGATIVE COVENANTS THAT RESTRICT OUR ACTIVITIES. Without bank approval or repaying the bank line of credit, our bank line of credit restricts us from:

- merging with another entity,
- selling a material portion of our assets other than in the ordinary course of business,
- issuing stock which in the aggregate exceeds thirty-five percent (35%) of our outstanding shares of common stock, and
- having any person hold more than twenty percent (20%) of our outstanding shares of common stock.

Our 7.00% Debentures and 5.75% Insured Quarterly Notes restrict us from:

- assuming additional mortgage indebtedness in excess of $5,000,000, and
- paying dividends on our common stock unless our consolidated shareholders' equity minus the value of our intangible assets exceed $25,800,000.

These negative covenants create the risk that we may be unable to take advantage of business and financing opportunities as they arise.

NEW LAWS OR REGULATIONS COULD HAVE A NEGATIVE IMPACT ON OUR FINANCIAL POSITION, RESULTS OF OPERATIONS OR CASH FLOWS. Changes in laws and regulations, including new accounting standards and tax law, could change the way in which we are required to record revenues, expenses, assets and liabilities. These types of regulations could have a negative impact on our financial position, cash flows, results of operations or access to capital.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own our corporate headquarters in Winchester, Kentucky. We own ten buildings used for field operations in the cities we serve. Also, we own a building in Laurel County, Kentucky used for equipment and materials storage.

We own approximately 2,500 miles of natural gas gathering, transmission, distribution, storage and service lines. These lines range in size up to twelve inches in diameter.

We hold leases for the storage of natural gas under 8,000 acres located in Bell County, Kentucky. We developed this property for the underground storage of natural gas.

We use all the properties described in the three paragraphs immediately above principally in connection with our regulated natural gas distribution, transmission and storage segment. See Note 14 of the Notes to Consolidated Financial Statements for a description of Delta's two business segments.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business.

Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.9 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others for further drilling and development. We have performed no reserve studies on these properties. Enpro produced a total of 143,000 Mcf of natural gas during fiscal 2009 from all the properties described in this paragraph.

A producer plans to conduct further exploration activities on part of Enpro's developed holdings. Enpro reserved the option to participate in wells drilled by this producer and also retained certain working and royalty interests in any production from future wells.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

We are not a party to any material pending legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted during the fourth quarter of 2009.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

We have paid cash dividends on our common stock each year since 1964. The frequency and amount of future dividends will depend upon our earnings, financial requirements and other relevant factors, including limitations imposed by the indenture for our Insured Quarterly Notes and Debentures (as described in Note 9 of the Notes to Consolidated Financial Statements).

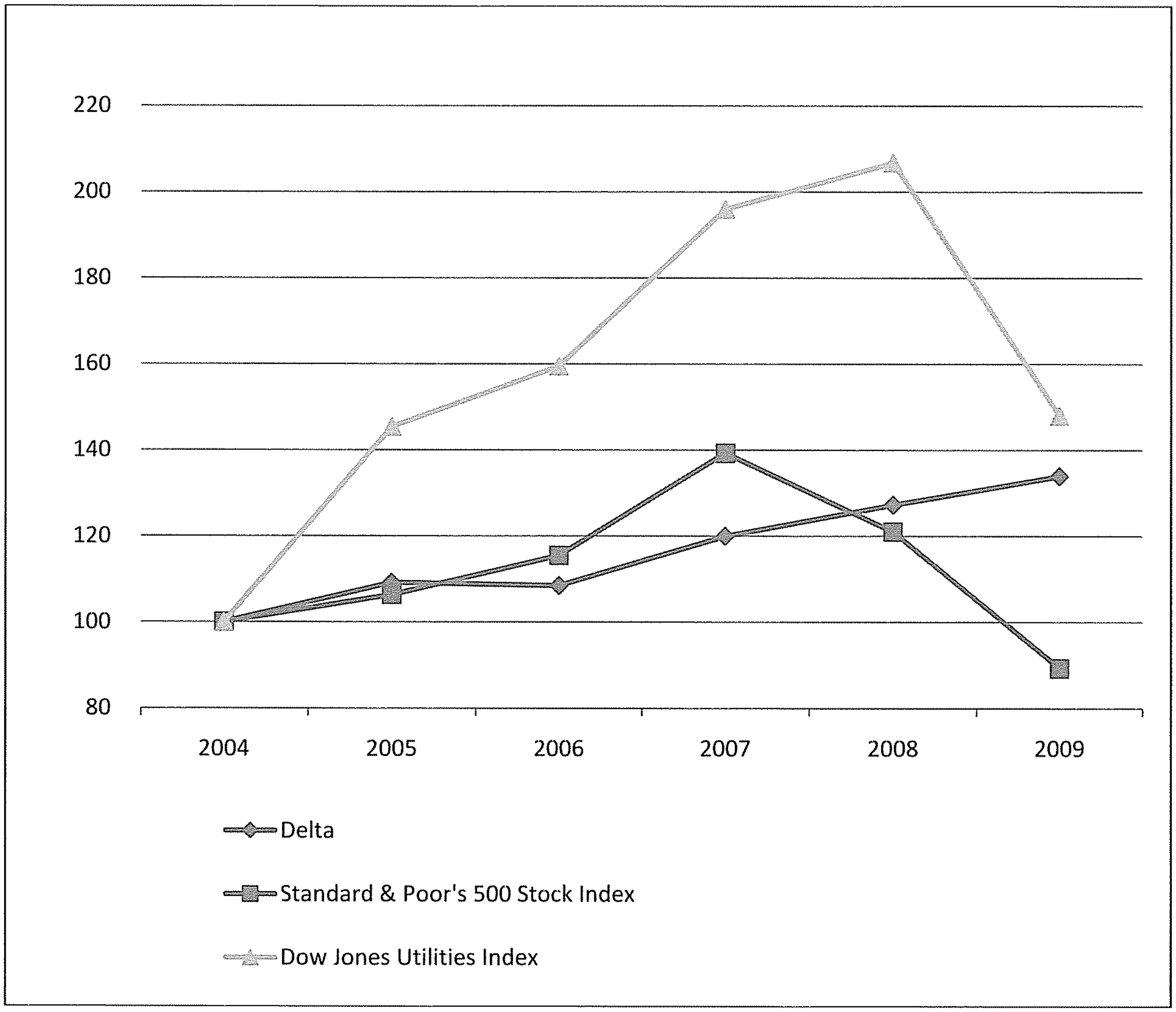
Our common stock is traded on the NASDAQ OMX Group and trades under the symbol "DGAS". There were 1,773 record holders of our common stock as of August 15, 2009. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ OMX Group and the cash dividends declared per share.

	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2009			
First	**28.60**	**11.70**	**.32**
Second	**26.00**	**18.01**	**.32**
Third	**26.86**	**18.68**	**.32**
Fourth	**24.21**	**18.46**	**.32**
Fiscal 2008			
First	25.83	23.50	.31
Second	25.84	24.10	.31
Third	26.73	24.11	.31
Fourth	32.19	24.25	.31

The closing sale prices shown above reflect prices between dealers and do not include markups or markdowns or commissions and may not necessarily represent actual transactions.

Comparison of Five-Year Cumulative Total Shareholder Return

The following graph sets forth a comparison of five year cumulative total shareholder return (equal to dividends plus stock price appreciation) among our common shares, the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index during the past five fiscal years. Information reflected on the graph assumes an investment of $100 on June 30, 2004 in each of our common shares, the Standard & Poor's Stock Index and the Dow Jones Utilities Index. Cumulative total return assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.



	2004	2005	2006	2007	2008	2009
Delta	100.0	109.2	108.5	120.0	127.3	133.9
Standard & Poor's 500 Stock Index	100.0	106.3	115.5	139.3	121.0	89.3
Dow Jones Utilities Index	100.0	145.4	159.5	195.9	206.8	148.0

Item 6. Selected Financial Data

For the Years Ended June 30,	**2009**	2008	2007	2006	2005
Summary of Operations ($)					
Operating revenues (a)(b)	**105,636,824**	112,657,117	98,168,391	117,247,144	84,181,233
Operating income (a)(b)(c)	**12,793,200**	15,663,736	12,968,043	12,757,507	12,490,127
Net income (a)(b)(c)	**5,210,729**	6,829,868	5,298,347	5,024,635	4,998,619
Basic and diluted earnings per common share (a)(b)(c)	**1.58**	2.08	1.62	1.55	1.55
Cash dividends declared per common share	**1.28**	1.24	1.22	1.20	1.18
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,306,026**	3,285,464	3,265,800	3,242,223	3,216,668
Total Assets ($)	**162,505,295**	170,814,856	160,400,950	155,554,125	144,762,217
Capitalization ($)					
Common shareholders' equity	**58,999,182**	57,593,585	54,428,471	52,609,724	50,799,454
Long-term debt (d)	**57,599,000**	58,318,000	58,625,000	58,790,000	52,707,000
Total capitalization	**116,598,182**	115,911,585	113,053,471	111,399,724	103,506,454
Short-Term Debt ($)(d)(e)	**4,853,103**	8,028,791	5,389,918	8,246,434	7,609,122
Other Items ($)					
Capital expenditures	**8,422,433**	5,563,667	8,082,918	7,781,396	5,338,356
Total property, plant and equipment	**199,254,216**	192,127,184	187,148,032	182,155,110	174,711,253

(a) We recorded 58,000 Mcf of unbilled sales at June 30, 2005, resulting in non-recurring increases of $1,246,000 in operating revenues, $617,000 in operating income, $379,000 in net income and $.12 in basic and diluted earnings per common share for fiscal 2005.

(b) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2007 and the rates were designed to generate additional annual revenue of $3,920,000.

(c) We recorded a $1,350,000 non-recurring inventory adjustment at December 31, 2008 for our gas in storage, as discussed in Note 15 of the Notes to Consolidated Financial Statements.

(d) During April, 2006, we issued $40,000,000 aggregate principal amount of 5.75% Insured Quarterly Notes due 2021. The net proceeds of the offering were $37,671,000. We used the net proceeds to redeem $23,700,000 and $10,200,000 aggregate principal amount of our 7.15% Debentures due 2018 and 6 5/8% Debentures due 2023, respectively. The remaining net proceeds of $3,830,000 were used to pay down our bank line of credit.

(e) Includes current portion of long-term debt.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview of 2009 and Future Outlook

Overview

The following is a discussion of the segments we operate, our corporate strategy for the conduct of our business within these segments and significant events that have occurred during 2009. Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production.

Earnings from the regulated segment are primarily influenced by sales and transportation volumes, the rates we charge our customers and the expenses we incur. In order for us to achieve our strategy of maintaining reasonable long-term earnings, cash flow and stock value, we must successfully manage each of these factors. Regulated sales volumes are temperature-sensitive. Our regulated sales volumes in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. The impact of winter temperatures on our revenues is partially reduced given our ability to adjust our winter rates for residential and small non-residential customers based on the degree to which actual winter temperatures deviate from normal.

Our non-regulated segment markets natural gas to large-use customers both on and off our regulated system. We endeavor to enter sales agreements when we can match estimated demand with a supply that provides an acceptable margin.

Earnings per share decreased between 2009 and 2008 by $.50 per share. Our non-regulated segment's contribution to earnings decreased as a result of decreased non-regulated sales volumes and lower sales prices that resulted in a $2,800,000 reduction in gross margins. Additionally, we incurred a non-recurring inventory adjustment for our gas in storage of $1,350,000 ($838,000 net of income tax benefit), as further discussed in Note 15 of the Notes to Consolidated Financial Statements.

Future Outlook

In 2010 and beyond, our success will depend, in part, on our regulated segment's ability to maintain a reasonable rate of return. The Kentucky Public Service Commission sets the rates we are permitted to charge our customers in the regulated segment. We monitor our need to file a general rate case with the Kentucky Public Service Commission to seek approval to adjust the rates we charge our regulated customers. The regulated segment's largest expense is gas supply, which we are permitted to pass through to our customers. We control remaining expenses through budgeting, approval and review.

Future profitability of the non-regulated segment is dependent on the business plans of a few industrial and other large use customers and the market prices of natural gas, all of which are out of our control. Although in Fiscal 2009 we experienced a decline of gross margins in this segment due to decreased prices and decreases in the volumes sold to our non-regulated customers due to a decrease in our non-regulated customers' gas requirements, we anticipate our non-regulated segment to continue to contribute to our consolidated net income in fiscal 2010 in a manner at least similar to fiscal 2009. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment margins related to our natural gas production activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

Liquidity and Capital Resources

Sources and Uses of Cash

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes, gains on the sale of assets and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable decreased to $3,653,000 at June 30, 2009, compared with $6,829,000 at June 30, 2008. The $3,176,000 decrease reflects a decrease in the cost of gas purchased for our gas in storage.

Our liquidity is impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $8,422,000, $5,564,000 and $8,803,000 during the fiscal years ended 2009, 2008 and 2007, respectively.

Long-term debt decreased to $57,599,000 at June 30, 2009, compared with $58,318,000 at June 30, 2008. The $719,000 decrease resulted from the redemption of the Debentures and Insured Quarterly Notes, which allow for limited redemptions to be made by certain holders or their beneficiaries.

Cash and cash equivalents were $123,000 at June 30, 2009 compared with $250,000 at June 30, 2008 and $188,000 at June 30, 2007. These changes in cash and cash equivalents are summarized in the following table:

($000)	**2009**	2008	2007
Provided by operating activities	**15,434**	6,592	14,486
Used in investing activities	**(7,956)**	(5,266)	(7,936)
Used in financing activities	**(7,605)**	(1,264)	(6,512)
Increase (decrease) in cash and cash equivalents	**(127)**	62	38

In 2009, cash provided by operating activities increased $8,842,000 as compared to 2008. In 2009, $8,626,000 less was paid for natural gas due to lower natural gas prices and $5,202,000 more cash was received from customers due to the timing of collections on customer accounts receivable. These increases were partially offset by a $1,932,000 increase in contributions we made to our pension plan and a $1,473,000 increase in cash paid for taxes.

In 2008, cash provided by operating activities decreased $7,894,000 as compared to 2007. In 2008, we paid $15,288,000 more for gas due to increased natural gas prices, increased volumes purchased and the timing of gas payables. This increase was partially offset due to $7,120,000 more cash received from customers due to increased prices and volumes sold.

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

In 2009, $6,341,000 more cash was used in financing activities due to increased net repayments on our bank line of credit.

In 2008, $5,248,000 less cash was used in financing activities due to increased net borrowings on our bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2010 to be approximately $6.3 million.

Due to the conditions in the debt and equity markets, we experienced a decline in the value of assets held by our defined benefit pension plan and thus we contributed $2,677,000 to the plan in fiscal 2009.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2009:

	Payments Due by Fiscal Year				
($000)	2010	2011-2012	2013-2014	After 2014	Total
Interest payments (a)	$ 4,192	$ 7,859	$ 7,400	$ 28,700	$ 48,151
Long-term debt (b)	1,200	2,400	2,400	52,799	58,799
Pension contributions (c)	500	1,000	1,000	9,182	11,682
Gas purchases (d)	3,764	143	—	—	3,907
Total contractual obligations (e)	$ 9,656	$ 11,402	$ 10,800	$ 90,681	$ 122,539

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2009 interest payments until the underlying obligation is satisfied. Interest on notes payable represents interest payments expected on the bank line of credit which extends through June 30, 2011. As of June 30, 2009, we have accrued $60,000 of interest related to uncertain tax positions. This amount has been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(b) See Note 9 of the Notes to Consolidated Financial Statements for a description of this debt. The cash obligations represent the maximum annual amount of redemptions to be made to certain holders or their beneficiaries through the debt maturity date. Our long-term debt does not have any sinking fund requirements.

(c) This represents currently projected contributions to the defined benefit plan through 2019, as recommended by our actuary.

(d) As of June 30, 2009, we had ten contracts which have minimum purchase obligations. These contracts have various terms with the last contract expiring November 1, 2010. The remainder of our gas purchase contracts are requirement-based contracts or if a minimum purchase obligation exists the contract does not extend for a time period greater than one month.

(e) We have other long-term liabilities which include deferred income taxes ($27,538,000), regulatory liabilities ($1,711,000), asset retirement obligations ($1,670,000) and deferred compensation ($281,000). Based on the nature of these items their expected settlement dates cannot be estimated.

All of our operating leases are year-to-year and cancelable at our option.

See Note 12 of the Notes to Consolidated Financial Statements for other commitments and contingencies.

Sufficiency of Future Cash Flows

Current economic conditions have resulted in increased credit risk for us due to the potential for default from our customers. For the twelve months ended June 30, 2009, we have experienced an increase in customer accounts written off, net of recoveries of $42,000 (10%). Based on current outstanding receivables and expecting this trend to continue into fiscal 2010, our allowance for doubtful accounts has increased to $819,000 at June 30, 2009, as compared to $465,000 at June 30, 2008. However, we are unable to estimate the impact this trend will have on future earnings and liquidity.

We expect that cash provided by operations, coupled with short-term and long-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that internally generated cash is not sufficient to satisfy operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available bank line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $3,653,000 was borrowed at June 30, 2009. The current bank line of credit extends through June 30, 2011.

Our ability to borrow on our bank line of credit is dependent on our compliance with covenants. Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of other Company exceeds $25,800,000 (thus no retained earnings were restricted); and

- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during fiscal 2009. We are not aware of any events that would cause us to be in default in fiscal 2010.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices, and we monitor our need to file rate requests with the Kentucky Public Service Commission for a general rate increase for our regulated services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on common shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge, and therefore the increase in revenue occurred more evenly throughout the year and was not as dependent on customer usage. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective October 20, 2007.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the use of assumptions and estimates regarding future events, including the likelihood of success of particular investments or initiatives, estimates of future prices or rates, legal and regulatory challenges and anticipated recovery of costs. Therefore, the possibility exists for materially different reported amounts under different conditions or assumptions. We consider an accounting estimate to be critical if (i) the accounting estimate requires us to make assumptions about matters that were reasonably uncertain at the time the accounting estimate was made, and (ii) changes in the estimate are reasonably likely to occur from period to period.

These critical accounting estimates should be read in conjunction with the Notes to Consolidated Financial Statements. We have other accounting policies that we consider to be significant; however, these policies do not meet the definition of critical accounting estimates, because they generally do not require us to make estimates or judgments that are particularly difficult or subjective.

Regulatory Accounting

Our accounting policies historically reflect the effects of the rate-making process in accordance with Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. Our regulated segment continues to be cost-of-service rate regulated, and we believe the application of Statement No. 71 to that segment continues to be appropriate. We must reaffirm this conclusion at each balance sheet date. If, as a result of a change in circumstances, it is determined that the regulated segment no longer meets the criteria of regulatory accounting under Statement No. 71, that segment will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of Statement No. 71 results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the Kentucky Public Service Commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base this conclusion on certain factors, including changes in the regulatory environment, recent rate orders issued by regulatory agencies and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred, or they represent probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our consolidated financial statements. We believe it is probable that we will recover the regulatory assets that have been recorded.

Pension

Our reported costs of providing pension benefits (as described in Note 5(a) of the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs associated with our defined benefit pension plan, for example, are impacted by employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plan and earnings on plan assets. Additionally, changes made to the provisions of the plan may impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

Changes in pension obligations associated with the above factors may not be immediately recognized as pension costs in the Consolidated Statements of Income, but may be deferred and amortized in the future over the average remaining service period of active plan participants. For the years ended June 30, 2009, 2008 and 2007, we recorded pension costs for our defined benefit pension plan of $608,000, $670,000 and $567,000, respectively.

Our pension plan assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting our discount rate assumption we considered rates of return on high-quality fixed-income investments that are expected to be available through the maturity dates of the pension benefits. Our expected long-term rate of return on pension plan assets was 7% for 2009 and was based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments. Our target investment allocation for equity investments includes allocations to domestic, international, and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We calculate the expected return on assets in our determination of pension costs based on the market value of assets at the measurement date. Using the market value recognizes investment gains or losses in the year in which they occur.

Based on an assumed long-term rate of return of 7%, discount rate of 6.25%, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plan will increase from $608,000 in 2009 to $1,040,000 in 2010. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2010 by approximately $34,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $43,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $45,000.

Effective May 9, 2008, any employees hired on and after that date are not eligible to participate in our defined benefit pension plan. Freezing the plan to new entrants did not impact the level of benefits for existing participants.

Effective July 1, 2008, we adopted the measurement date provision of Financial Accounting Standards Board Statement No. 158 entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which required us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 were $760,000. Of this amount, $152,000 is attributable to the change in measurement dates and (net of tax effects of $58,000) was charged directly to retained earnings on July 1, 2008.

Provisions for Doubtful Accounts

We encounter risks associated with the collection of our accounts receivable. As such, we record a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, we primarily utilize our historical experience related to accounts written-off. Quarterly, at a minimum, we review the reserve for reasonableness based on the level of revenue and the aging of the receivable balance. The underlying assumptions used for the allowance can change from period to period and the allowance could potentially cause a material impact to the Consolidated Statements of Income and working capital. The actual weather, commodity prices and other internal and external economic conditions, such as the mix of the customer base between residential, commercial and industrial, may vary significantly from our assumptions and may impact operating income.

Unbilled Revenues and Gas Costs

At each month-end, we estimate the gas service that has been rendered from the date the customer's meter was last read to month-end. This estimate of unbilled usage is based on projected base load usage for each day unbilled plus projected weather-sensitive usage for each degree day during the unbilled period. Unbilled revenues and gas costs are calculated from the estimate of unbilled usage multiplied by the rates in effect at month-end. Actual usage patterns may vary from these assumptions and may impact operating income.

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to Federal regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations are recorded at the time the obligations are incurred. We do not recognize asset retirement obligations relating to assets with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities are accreted for the change in their present value, through depreciation, and the initial capitalized costs are depreciated over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the depreciation and accretion are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement date and the assumed credit-adjusted risk-free interest rate. Our asset retirement obligations are discussed in Note 3 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

Significant management judgment is generally required during the process of adopting new accounting pronouncements. See Note 2 of the Notes to Consolidated Financial Statements for a discussion of these pronouncements.

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as "estimates", "attempts", "expects", "monitors", "plans", "anticipates", "intends", "continues", "strives" ,"seeks", "will rely", "believes" and similar expressions.

These forward-looking statements include, but are not limited to, statements about:

- operational plans,
- the cost and availability of our natural gas supplies,
- capital expenditures,
- sources and availability of funding for our operations and expansion,
- anticipated growth and growth opportunities through system expansion and acquisition,
- competitive conditions that we face,
- production, storage, gathering and transportation activities,
- acquisition of service franchises from local governments,
- pension fund costs and management,
- contractual obligations and cash requirements,
- management of our gas supply and risks due to potential fluctuation in the price of natural gas,
- revenues, income, margins and profitability,
- efforts to purchase and transport locally produced natural gas,
- recovery of regulatory assets,
- regulatory and legislative matters, and
- dividends.

Our forward-looking statements are not guarantees of future performance and are based upon currently available competitive, financial and economic data along with our operating plans.

Item 1A. Risk Factors lists factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results.

Results of Operations

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented in the Consolidated Statements of Income, is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for discussion of our forward contracts.

In the following table we set forth variations in our gross margins for the last two fiscal years compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

($000)	**2009 compared to 2008**	2008 compared to 2007
Increase (decrease) in regulated gross margins		
Gas sales	**404**	1,349
On-system transportation	**(343)**	203
Off-system transportation	**(78)**	884
Other	**39**	52
Intersegment elimination (a)	**592**	(376)
Total	**614**	2,112
Increase (decrease) in non-regulated gross margins		
Gas sales	**(2,145)**	1,065
Other	**(93)**	114
Intersegment elimination (a)	**(592)**	376
Total	**(2,830)**	1,555
Increase (decrease) in consolidated gross margins	**(2,216)**	3,667
Percentage increase (decrease) in regulated volumes		
Gas sales	**3**	(5)
On-system transportation	**(15)**	(4)
Off-system transportation	**(6)**	29
Percentage increase (decrease) in non-regulated gas sales volumes	**(22)**	10

(a) Intersegment eliminations represent the transportation fee charged by the regulated segment to the non-regulated segment.

Heating degree days were 101% of normal thirty year average temperatures for fiscal 2009, as compared with 96% and 95% of normal temperatures for 2008 and 2007, respectively. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

In 2009, consolidated gross margins decreased $2,216,000 (6%) due to decreased non-regulated gross margins of $2,830,000 (26%) offset by increased regulated gross margins of $614,000 (2%). Our non-regulated gross margins decreased due to a 22% decrease in volumes sold and lower sales prices. The non-regulated volumes sold decreased due to a decrease in our non-regulated customers' gas requirements. Our regulated gross margin for gas sales increased $404,000 (2%) due to a 3% increase in volumes sold due to colder weather than in the previous year.

In 2008, consolidated gross margins increased $3,667,000 (11%) due to increased regulated and non-regulated gross margins of $2,112,000 (9%) and $1,555,000 (16%), respectively. Our regulated gross margins increased due to increased base rates which became effective October 20, 2007 and a 29% increase in off-system volumes transported. Our non-regulated gross margin for gas sales increased due to a 10% increase in volumes sold.

Operations and Maintenance

In 2009, operations and maintenance expense increased $901,000 (6%). The increase was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 15 of the Notes to Consolidated Financial Statements) and increased uncollectible expense ($231,000). These increases were partially offset by decreased storage maintenance expense ($479,000) and decreased accrued bonuses ($355,000).

In 2008, operations and maintenance expense increased $1,544,000 (12%). The increase was primarily due to increased uncollectible expense ($326,000), increased storage maintenance expense ($307,000), increased labor expense ($274,000), increased transportation expense ($165,000) and increase maintenance of transmission and distribution mains ($133,000).

Depreciation and Amortization

In 2008, depreciation and amortization decreased $527,000 (11%) due to lower depreciation rates approved by the Kentucky Public Service Commission that became effective October 20, 2007. The decrease was partially offset by increases in depreciable plant resulting from capital expenditures which relate to the replacement and improvement of our transmission, distribution, gathering, storage and general facilities.

Other Income and Deductions, Net

In 2009, other income and deductions, net decreased $130,000 (155%). The decreases were due to decreases in bank interest earned, decreases in the cash surrender value of officers' life insurance as well as decreases in the fair value of the supplemental retirement trust. The decreases in the fair value of the supplemental retirement trust were offset by reductions in operating expense resulting from corresponding deceases in the liability of the plan.

Other Interest

In 2009, other interest decreased $213,000 (30%) due to a decrease in the average interest rate on our bank line of credit.

In 2008, other interest increased $139,000 (25%) due to increased net borrowings on our bank line of credit.

Income Tax Expense

In 2009, income tax expense decreased $1,139,000 (27%) due to a decrease in net income before income taxes.

In 2008, income tax expense increased $990,000 (31%) due to an increase in net income before income taxes.

Basic and Diluted Earnings Per Common Share

For the fiscal years ended June 30, 2009 and 2008, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balance on our bank line of credit was $3,653,000 and $6,829,000 on June 30, 2009 and 2008, respectively. The weighted average interest rate on our bank line of credit was 1.8% and 3.2% as of June 30, 2009 and 2008, respectively. Based on the amount of our outstanding bank line of credit on June 30, 2009 and 2008, a 1% (one hundred basis points) increase in our average interest rate would result in a decrease in our annual pre-tax net income of $37,000 and $68,000, respectively. Effective June 30, 2009 the bank line of credit was extended through June 30, 2011. The extension increased the interest rate on the used bank line of credit from the London Interbank Offered Rate plus .75% to the London Interbank Offered Rate plus 1.5%.

Item 8. Financial Statements and Supplementary Data

Schedules other than those listed above are omitted because they are not required, are not applicable or the required information is shown in the financial statements or notes thereto.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's ("SEC") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a – 15(e) and 15d – 15(e) under the Exchange Act) as of June 30, 2009 and based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of June 30, 2009 based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of June 30, 2009.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended June 30, 2009 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting. That report immediately follows:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Delta Natural Gas Company, Inc.:

We have audited the internal control over financial reporting of Delta Natural Gas Company, Inc. (the "Company") as of June 30, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Certification of the Chief Executive Officer and Certification of the Chief Financial Officer. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended June 30, 2009 of the Company and our report dated August 31, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule, and included explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement 109* and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 31, 2009

Item 9B. Other Information

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance of the Registrant*

We have a Business Code of Conduct and Ethics that applies to all directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. You can find our Business Code of Conduct and Ethics on our website by going to the following address: http://www.deltagas.com. We will post any amendments to the Business Code of Conduct and Ethics, as well as any waivers that are required to be disclosed by the rules of either the Securities and Exchange Commission or the NASDAQ OMX Group, on our website.

Our Board of Directors has adopted charters for the Audit, Corporate Governance and Compensation and Executive Committees of the Board of Directors. You can find these documents on our website by going to the following address: http://www.deltagas.com and clicking on the appropriate link.

You can also obtain a printed copy of any of the materials referred to above by contacting us at the following address:

Delta Natural Gas Company, Inc.
Attn: John B. Brown
3617 Lexington Road
Winchester, KY 40391
(859) 744-6171

The Audit Committee of our Board of Directors is an "audit committee" for purposes of Section 3(a)(58) of the Securities Exchange Act of 1934.

The other information required by this Item is incorporated herein by reference to the applicable information in the proxy statement for our 2009 annual meeting.

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 14. Principal Accountant Fees and Services

Registrant intends to file a definitive proxy statement with the Commission pursuant to Regulation 14A (17 CFR 240.14a) no later than 120 days after the close of the fiscal year. In accordance with General Instruction G(3) to Form 10-K, the information called for by Items 10 (except for the language above in Item 10 in this report), 11, 12, 13 and 14 is incorporated herein by reference to the definitive proxy statement.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements
See Index at Item 8

(2) Financial Statement Schedules
See Index at Item 8

(3) Exhibits

Exhibit No.

3(i)	Registrant's Amended and Restated Articles of Incorporation (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(i) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.
3(ii)	Registrant's Amended and Restated By-Laws (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(ii) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2007.
4(a)	The Indenture dated March 1, 2006 in respect of 5.75% Insured Quarterly Notes due April 1, 2021, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-3 (Reg. No. 333-132322) dated March 31, 2006.
4(b)	The Indenture dated January 1, 2003 in respect of 7% Debentures due February 1, 2023, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-2 (Reg. 333-100852) dated October 30, 2002.
10(a)	Gas Sales Agreement, dated May 1, 2005, by and between the Registrant and Atmos Energy Marketing, LLC is incorporated herein by reference to Exhibit 10(c) to the Registrant's Form 10-K (File No. 000-08788), for the period ended June 30, 2005.
10(b)	Gas Sales Agreement, dated May 1, 2003, by and between the Registrant and Atmos Energy Marketing, LLC is incorporated herein by reference to Exhibit 10(d) to the Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2003.
10(c)	Base Contract for Short-Term Sale and Purchase of Natural Gas, dated January 1, 2002, by and between M & B Gas Services, Inc. and Registrant, is incorporated herein by reference to Exhibit 10(n) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.
10(d)	Gas Transportation Agreement (Service Package 9069), dated December 19, 1994, by and between Tennessee Gas Pipeline Company and Registrant is incorporated herein by reference to Exhibit 10(e) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.
10(e)	Agreement to transport natural gas between Registrant and Nami Resources Company L.L.C. is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated March 23, 2005.
10(f)	GTS Service Agreement (Service Agreement No. 37815), dated November 1, 1993, by and between Columbia Gas Transmission Corporation and Registrant is incorporated herein by reference to Exhibit 10(f) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.
10(g)	FTS1 Service Agreement (Service Agreement No. 4328), dated October 4, 1994, by and between Columbia Gulf Transmission Company and Registrant is incorporated herein by reference to Exhibit 10(g) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.
10(h)	Gas Storage Lease, dated October 4, 1995, by and between Judy L. Fuson, Guardian of Jamie Nicole Fuson, a minor, and Lonnie D. Ferrin and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant is incorporated herein by reference to Exhibit 10(j) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.
10(i)	Gas Storage Lease, dated November 6, 1995, by and between Thomas J. Carnes, individually and as Attorney-in-fact and Trustee for the individuals named therein, and Registrant, is incorporated herein by reference to Exhibit 10(k) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.
10(j)	Deed and Perpetual Gas Storage Easement, dated December 21, 1995, by and between Katherine M. Cornelius, William Cornelius, Frances Carolyn Fitzpatrick, Isabelle Fitzpatrick Smith and Kenneth W.

Smith and Registrant is incorporated herein by reference to Exhibit 10(l) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(k) Underground Gas Storage Lease and Agreement, dated March 9, 1994, by and between Equitable Resources Exploration, a division of Equitable Resources Energy Company, and Lonnie D. Ferrin and Amendment No. 1 and Novation to Underground Gas Storage Lease and Agreement, dated March 22, 1995, by and between Equitable Resources Exploration, Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(m) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(l) Oil and Gas Lease, dated July 19, 1995, by and between Meredith J. Evans and Helen Evans and Paddock Oil and Gas, Inc.; Assignment, dated June 15, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; Assignment, dated August 31, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(o) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10(m) Loan Agreement, dated October 31, 2002, by and between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(i) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(n) Promissory Note, in the original principal amount of $40,000,000, made by Registrant to the order of Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2002.

10(o) Modification Agreement extending to October 31, 2004 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to the Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2003.

10(p) Modification Agreement extending to October 31, 2005 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to the Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2004.

10(q) Modification Agreement extending to October 31, 2007 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to the Registrant's Form 8-K (File No. 000-08788) dated August 19, 2005.

10(r) Modification Agreement extending to October 31, 2009 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2007.

10(s) Modification Agreement extending to June 30, 2011 the Promissory Note and Loan Agreement dated October 31, 2002 between the Registrant and Branch Banking and Trust Company, is incorporated herein by reference to Exhibit 10(a) to the Registrant's Form 8-K (File No. 000-08788) dated June 30, 2009.

10(t) Employment agreements between Registrant and three officers, those being John B. Brown, Johnny L. Caudill, and Glenn R. Jennings, are incorporated herein by reference to Exhibit 10(k) to Registrant's Form 10-Q (File No. 000-08788) for the period ended March 31, 2000.

10(u) Employment agreement between Registrant and Brian S. Ramsey is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated November 21, 2008.

10(v) Supplemental retirement benefit agreement and trust agreement between Registrant and Glenn R. Jennings is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated February 25, 2005.

12 Computation of the Consolidated Ratio of Earnings to Fixed Charges.

21 Subsidiaries of the Registrant.

23 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 31st day of August, 2009.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 31, 2009

(ii) Principal Financial Officer and Principal Accounting Officer:

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 31, 2009

(iii) A Majority of the Board of Directors:

/s/Linda K. Breathitt (Linda K. Breathitt)	Director	August 31, 2009
/s/Lanny D. Greer (Lanny D. Greer)	Director	August 31, 2009
/s/Billy Joe Hall (Billy Joe Hall)	Director	August 31, 2009
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 31, 2009
/s/Lewis N. Melton (Lewis N. Melton)	Director	August 31, 2009
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 31, 2009
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 31, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Delta Natural Gas Company, Inc.:

We have audited the accompanying consolidated balance sheets of Delta Natural Gas Company, Inc. (the "Company") as of June 30, 2009 and 2008, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended June 30, 2009. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at June 30, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on July 1, 2007 the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109.*

As discussed in Note 2 to the consolidated financial statements, on July 1, 2008 the Company adopted the measurement date provision of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated August 31, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 31, 2009

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Years Ended June 30,	**2009**	2008	2007
Operating Revenues	**$ 105,636,824**	$ 112,657,117	$ 98,168,391
Operating Expenses			
Purchased gas	**$ 72,077,631**	$ 76,882,387	$ 66,060,368
Operation and maintenance	**15,030,287**	14,128,620	12,584,607
Depreciation and amortization	**3,855,099**	4,171,145	4,697,639
Taxes other than income taxes	**1,880,607**	1,811,229	1,857,734
Total operating expenses	**$ 92,843,624**	$ 96,993,381	$ 85,200,348
Operating Income	**$ 12,793,200**	$ 15,663,736	$ 12,968,043
Other Income and Deductions, Net	**$ (46,418)**	$ 83,521	$ 134,265
Interest Charges			
Interest on long-term debt	**$ 3,648,243**	$ 3,677,983	$ 3,694,389
Other interest	**492,151**	705,240	565,790
Amortization of debt expense	**387,263**	387,266	387,082
Total interest charges	**$ 4,527,657**	$ 4,770,489	$ 4,647,261
Income Before Income Taxes	**$ 8,219,125**	$ 10,976,768	$ 8,455,047
Income Tax Expense	**$ 3,008,396**	$ 4,146,900	$ 3,156,700
Net Income	**$ 5,210,729**	$ 6,829,868	$ 5,298,347
Basic and Diluted Earnings Per Common Share	**$ 1.58**	$ 2.08	$ 1.62
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**3,306,026**	3,285,464	3,265,800
Dividends Declared Per Common Share	**$ 1.28**	$ 1.24	$ 1.22

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows

For the Years Ended June 30,	2009	2008	2007
Cash Flows From Operating Activities			
Net income	$ **5,210,729**	$ 6,829,868	$ 5,298,347
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	**4,362,241**	4,660,410	5,157,922
Provision for inventory adjustment	**1,350,300**	—	—
Deferred income taxes and investment tax credits	**2,135,347**	2,095,000	2,345,300
Gain on sale of property, plant and equipment	**(156,023)**	(16,955)	—
Change in cash surrender value of officer's life insurance	**31,651**	(18,704)	(24,577)
Other, net	**(423,672)**	(219,041)	(205,827)
(Increase) decrease in assets			
Accounts receivable	**7,334,709**	(5,016,055)	1,746,732
Gas in storage	**3,379,325**	(2,634,602)	(475,801)
Deferred gas cost	**2,255,751**	(1,670,877)	(1,116,773)
Materials and supplies	**(93,516)**	(38,568)	(87,859)
Prepayments	**(2,173,506)**	(129,153)	(897,682)
Other assets	**(77,411)**	(56,686)	(173,310)
Increase (decrease) in liabilities			
Accounts payable	**(7,418,187)**	1,920,832	3,835,813
Accrued taxes	**(773,761)**	890,309	(1,061,563)
Other current liabilities	**486,664**	(889)	148,901
Other liabilities	**3,279**	(2,358)	(3,717)
Net cash provided by operating activities	$ **15,433,920**	$ 6,592,531	$ 14,485,906
Cash Flows From Investing Activities			
Capital expenditures	$ **(8,422,433)**	$ (5,563,667)	$ (8,082,918)
Proceeds from sale of property, plant and equipment	**526,763**	297,425	146,810
Other	**(60,000)**	—	—
Net cash used in investing activities	$ **(7,955,670)**	$ (5,266,242)	$ (7,936,108)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows (continued)

For the Years Ended June 30,	**2009**	2008	2007
Cash Flows From Financing Activities			
Dividends on common stock	**$ (4,231,239)**	$ (4,073,278)	$ (3,983,909)
Issuance of common stock	**520,407**	477,155	504,309
Long-term debt issuance expense	—	—	(10,970)
Repayment of long-term debt	**(719,000)**	(307,000)	(165,000)
Borrowings on bank line of credit	**74,107,057**	64,602,956	51,518,605
Repayment of bank line of credit	**(77,282,745)**	(61,964,083)	(54,375,121)
Net cash used in financing activities	**$ (7,605,520)**	$ (1,264,250)	$ (6,512,086)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ (127,270)**	$ 62,039	$ 37,712
Cash and Cash Equivalents, Beginning of Year	**249,859**	187,820	150,108
Cash and Cash Equivalents, End of Year	**$ 122,589**	$ 249,859	$ 187,820

Supplemental Disclosures of Cash Flow Information

Cash paid during the year for			
Interest	**$ 4,148,311**	$ 4,383,367	$ 4,232,155
Income taxes (net of refunds)	**1,630,937**	1,376,093	1,763,518

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets

As of June 30,		2009		2008
Assets				
Current Assets				
Cash and cash equivalents	$	**122,589**	$	249,859
Accounts receivable, less accumulated allowances for doubtful accounts of $819,000 and $465,000 in 2009 and 2008, respectively		**4,085,867**		11,437,219
Gas in storage, at average cost (Note 15)		**9,746,768**		14,476,393
Deferred gas costs (Notes 1 and 13)		**2,356,943**		4,612,752
Materials and supplies, at average cost		**662,805**		565,333
Prepayments		**2,415,527**		2,683,854
Total current assets	$	**19,390,499**	$	34,025,410
Property, Plant and Equipment	$	**199,254,216**	$	192,127,184
Less – Accumulated provision for depreciation		**(70,616,271)**		(67,754,068)
Net property, plant and equipment	$	**128,637,945**	$	124,373,116
Other Assets				
Cash surrender value of officers' life insurance (face amount of $1,158,091)	$	**412,661**	$	444,312
Prepaid pension cost (Note 5)		—		1,423,932
Regulatory assets (Note 1)		**11,394,844**		7,713,358
Unamortized debt expense and other (Notes 1 and 9)		**2,669,346**		2,834,728
Total other assets	$	**14,476,851**	$	12,416,330
Total assets	$	**162,505,295**	$	170,814,856

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets (continued)

As of June 30,		**2009**		2008
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable	$	**4,691,152**	$	12,154,432
Notes payable (Note 8)		**3,653,103**		6,828,791
Current portion of long-term debt (Notes 9 and 10)		**1,200,000**		1,200,000
Accrued taxes		**983,376**		1,656,391
Customers' deposits		**508,209**		505,058
Accrued interest on debt		**857,810**		865,727
Accrued vacation		**712,216**		720,625
Deferred income taxes		**814,549**		1,483,700
Other liabilities		**487,925**		418,239
Total current liabilities	**$**	**13,908,340**	$	25,832,963
Long-term Debt (Notes 9 and 10)	**$**	**57,599,000**	$	58,318,000
Long-term Liabilities				
Deferred income taxes	$	**27,537,908**	$	24,576,000
Investment tax credits		**144,500**		177,800
Regulatory liabilities (Note 1)		**1,710,099**		2,144,951
Accrued pension		**430,095**		—
Asset retirement obligations and other (Note 3)		**2,176,171**		2,171,557
Total long-term liabilities	**$**	**31,998,773**	$	29,070,308
Commitments and Contingencies (Note 12)				
Total liabilities	**$**	**103,506,113**	$	113,221,271
Shareholders' Equity				
Common shares ($1.00 par value), 20,000,000 shares authorized; 3,318,046 and 3,295,759 shares outstanding at June 30, 2009 and June 30, 2008, respectively	$	**3,318,046**	$	3,295,759
Premium on common shares		**44,465,601**		43,967,481
Retained earnings		**11,215,535**		10,330,345
Total shareholders' equity	**$**	**58,999,182**	$	57,593,585
Total liabilities and shareholders' equity	**$**	**162,505,295**	$	170,814,856

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Delta Natural Gas Company, Inc.

Consolidated Statements of Changes in Shareholders' Equity

For the Years Ended June 30,	**2009**	2008	2007
Common Shares			
Balance, beginning of year	**$ 3,295,759**	$ 3,277,106	$ 3,256,043
Issuance of common stock $1.00 par value of 22,287, 18,653, and 21,063 shares issued in 2009, 2008 and 2007, respectively	**22,287**	18,653	21,063
Balance, end of year	**$ 3,318,046**	$ 3,295,759	$ 3,277,106
Premium on Common Shares			
Balance, beginning of year	**$ 43,967,481**	$ 43,508,979	$ 43,025,733
Issuance of common stock	**498,120**	458,502	483,246
Balance, end of year	**$ 44,465,601**	$ 43,967,481	$ 43,508,979
Retained Earnings			
Balance, beginning of year	**$ 10,330,345**	$ 7,642,386	$ 6,327,948
Adoption of FASB Interpretation No. 48	—	(68,631)	—
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	**(94,300)**	—	—
Balance, beginning of year, as adjusted	**$ 10,236,045**	$ 7,573,755	$ 6,327,948
Net income	**5,210,729**	6,829,868	5,298,347
Cash dividends declared on common shares (See Consolidated Statements of Income for rates)	**(4,231,239)**	(4,073,278)	(3,983,909)
Balance, end of year	**$ 11,215,535**	$ 10,330,345	$ 7,642,386
Common Shareholders' Equity			
Balance, beginning of year	**$ 57,593,585**	$ 54,428,471	$ 52,609,724
Adoption of FASB Interpretation No. 48	—	(68,631)	—
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	**(94,300)**	—	—
Balance, beginning of year, as adjusted	**$ 57,499,285**	$ 54,359,840	$ 52,609,724
Net income	**5,210,729**	6,829,868	5,298,347
Issuance of common shares	**520,407**	477,155	504,309
Dividends on common shares	**(4,231,239)**	(4,073,278)	(3,983,909)
Balance, end of year	**$ 58,999,182**	$ 57,593,585	$ 54,428,471

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Principles of Consolidation Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 37,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated. In the preparation of the Consolidated Financial Statements, we evaluated subsequent events after the balance sheet date of June 30, 2009 through August 31, 2009, the filing date of this Form 10-K.

(b) Cash Equivalents For the purposes of the Consolidated Statements of Cash Flows, all temporary cash investments with a maturity of three months or less at the date of purchase are considered cash equivalents.

(c) Property, Plant and Equipment Property, plant and equipment is stated at original cost, which includes materials, labor, labor related costs and an allocation of general and administrative costs. Construction work in progress has been included in the rate base for determining customer rates, and therefore an allowance for funds used during construction has not been recorded. The cost of regulated plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense, less salvage value, is charged to the accumulated provision for depreciation.

(d) Depreciation We determine the provision for depreciation using the straight-line method and by the application of rates to various classes of utility plant. The rates are based upon the estimated service lives of the properties and were equivalent to composite rates of 2.1%, 2.3%, and 2.7% of average depreciable plant for 2009, 2008 and 2007, respectively. Effective October 20, 2007 we implemented new depreciation rates allowed by the Kentucky Public Service Commission in our 2007 rate case which increased the remaining depreciable lives of our depreciable assets.

(e) Maintenance All expenditures for maintenance and repairs of units of property are charged to the appropriate maintenance expense accounts in the month incurred. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired.

(f) Gas Cost Recovery We have a Gas Cost Recovery ("GCR") clause which provides for a dollar-tracker that matches revenues and gas costs and provides eventual dollar-for-dollar recovery of all gas costs incurred by the regulated segment and approved by the Kentucky Public Service Commission. We expense gas costs based on the amount of gas costs recovered through revenue. Any differences between actual gas costs and those estimated costs billed are deferred and reflected in the computation of future billings to customers using the GCR mechanism.

(g) Revenue Recognition We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	**2009**	2008
Unbilled revenues ($)	**1,386**	1,579
Unbilled gas costs ($)	**519**	736
Unbilled volumes (Mcf)	**55**	51

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(h) Excise Taxes Certain excise taxes levied by state or local governments are collected by Delta from our customers. These taxes are accounted for on a net basis and therefore are not included as revenues in the accompanying Consolidated Statements of Income.

(i) Revenues and Customer Receivables We serve 37,000 customers in central and southeastern Kentucky. Revenues and customer receivables arise primarily from sales of natural gas to customers and from transportation services for others. Provisions for doubtful accounts are recorded to reflect the expected net realizable value of accounts receivable. Customer accounts are charged off when deemed to be uncollectible or when turned over to a collection agency to pursue.

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

(k) Rate Regulated Basis of Accounting Our regulated operations follow the accounting and reporting requirements of Financial Accounting Standards Board Statement No. 71, entitled Accounting for the Effects of Certain Types of Regulation. The economic effects of regulation can result in a regulated company recovering costs from customers in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this results, costs are deferred as assets on the Consolidated Balance Sheets (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities). The amounts recorded as regulatory assets and regulatory liabilities are as follows:

($000)	**2009**	2008
Regulatory assets		
Current assets		
Deferred gas costs	**2,357**	4,613
Other assets		
Conservation/efficiency program expenses	**109**	—
Loss on extinguishment of debt	**2,348**	2,539
Asset retirement obligations	**1,464**	1,352
Accrued pension	**7,309**	3,538
Regulatory case expenses	**165**	285
Total other assets	**11,395**	7,714
Total regulatory assets	**13,752**	12,327
Regulatory liabilities		
Accrued cost of removal on long-lived assets	**304**	615
Regulatory liability for deferred income taxes	**1,406**	1,530
Total regulatory liabilities	**1,710**	2,145

Deferred gas costs are presented every three months to the Kentucky Public Service Commission for recovery in accordance with the gas cost recovery rate mechanism. Amounts recoverable under our conservation and efficiency program are presented annually to the Kentucky Public Service Commission for recovery in accordance with the conservation/efficiency program cost recovery rate mechanism. We are currently earning a return on loss on extinguishment of debt. Asset retirement costs are recovered through customer rates as they are included in our depreciation rates. Pension expenses and regulatory case expenses are recovered through customer rates as allowed operating expenses.

(l) Impairment of Long-Lived Assets We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. In the opinion of management, our long-lived assets are appropriately valued in the accompanying consolidated financial statements.

(m) Derivatives We purchase and sell natural gas. Certain of our gas purchase and sale contracts qualify as a derivative under Financial Accounting Standards Board Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. All such contracts have been designated as normal purchases and sales and as such are accounted for under the accrual basis and are not recorded at fair value in the accompanying consolidated financial statements.

(n) Marketable Securities We have a supplemental retirement benefit agreement with Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer which is a non-qualified deferred compensation plan. The agreement establishes an irrevocable rabbi trust, in which the assets of the trust are earmarked to pay benefits under the agreement. We have recognized a liability related to the obligation to pay these benefits to Mr. Jennings. We make discretionary contributions to the trust which increases both the trust assets and the deferred compensation liability.

The assets of the trust consist of exchange traded mutual funds and are classified as trading securities under Financial Accounting Standards Board Statement No. 115, entitled Accounting for Certain Investments in Debt and Equity Securities. The assets are recorded at fair value on the Consolidated Balance Sheets based on observable market prices from active markets. Net realized and unrealized gains and losses are included in earnings each period to effectively offset the corresponding earnings impact associated with the change in the fair value of the deferred compensation liability to which the assets relate.

(2) New Accounting Pronouncements

Recently Adopted Pronouncements

In July, 2006, the FASB issued Interpretation No. 48, entitled Accounting for Uncertainty in Income Taxes, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Financial Accounting Standards Board Statement No. 109, entitled Accounting for Income Taxes. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. We adopted the provisions of Interpretation No. 48 on July 1, 2007. The adoption of Interpretation No. 48 resulted in an adjustment to beginning retained earnings of $69,000. At adoption, the total amount of gross unrecognized tax benefits for uncertain tax positions, including positions impacting only the timing of tax benefits, was $668,000, of which $97,000 related to interest. Note 4 of the Notes to Consolidated Financial Statements further discusses our income taxes.

In September, 2006, the Financial Accounting Standards Board issued Statement No. 158, entitled Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Statement No. 158 contains provisions relating to disclosure and recognition which we adopted effective June 30, 2007. Additionally, Statement No. 158 requires employers who sponsor defined benefit plans to measure assets and benefit obligations as of the end of the employer's fiscal year in fiscal years beginning after December 15, 2007. Effective July 1, 2008, we adopted the measurement date provision of Statement No. 158, which required us to change the measurement date of our defined benefit plan from March 31 to June 30. Pension costs from April 1, 2008 to June 30, 2009 were $760,000. Of this amount, $152,000 was attributable to the change in measurement dates. Accordingly, we recognized a $119,000 decrease in our prepaid pension expense and a $33,000 decrease in our unrecovered pension expense regulatory asset. These decreases were accounted for as a reduction to beginning retained earnings as of July 1, 2008, net of $58,000 of tax.

In September, 2006, the Financial Accounting Standards Board issued Statement No. 157, entitled Fair Value Measures, and in February, 2007 it issued Statement No. 159, entitled The Fair Value Option for Financial Assets and Financial Liabilities. The Statements define fair value, establish a framework for measuring fair value in accordance with accounting principles generally accepted in the United States of America and expand disclosure requirements about fair value measurements.

Under Statement No. 157, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition under Statement No. 157 focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although Statement No. 157 does not require additional fair value measurements, it applies to other accounting pronouncements that require or permit fair value measurements.

We determine the fair value of financial assets and liabilities based on the following fair value hierarchy, as prescribed by Statement No. 157, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3 – Unobservable inputs which require the reporting entity to develop its own assumptions.

Effective July 1, 2008, we adopted Statement No. 157 for all financial instruments. There was no cumulative effect adjustment to retained earnings as a result of adopting Statement No. 157.

Statement No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Although Statement No. 159 was effective for our fiscal year beginning July 1, 2008, we do not currently have any financial assets or financial liabilities for which the provisions of Statement No. 159 has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with this standard.

As of June 30, 2009, our financial assets and liabilities that are measured at fair value on a recurring basis consist of the assets of our supplemental retirement benefit trust. As of June 30, 2009, the assets of the trust were $281,000 and are included in unamortized debt expense and other on the Consolidated Balance Sheets. The offsetting liability is included in asset retirement obligations and other on the Consolidated Balance Sheets. Contributions to the trust are presented in other investing activities on the 2009 Consolidated Statement of Cash Flows. The liability is not considered a financial liability within the scope of Statement No. 157. The assets of the trust are recorded at fair value and consist of exchange traded mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the Statement No. 157 hierarchy.

In March, 2008, the Financial Accounting Standards Board issued Statement No. 161, entitled Disclosures about Derivative Instruments and Hedging Activities. Statement No. 161 enhances the disclosures as required by Statement No. 133, entitled Accounting for Derivative Instruments and Hedging Activities. Entities are required to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged instruments are accounted for under Statement No. 133 and its related interpretations, and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. Effective March 31, 2009, we adopted the provisions of Statement No. 161. To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. We mitigate price risk by efforts to balance supply and demand. None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Statement No. 133.

In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 157-4, entitled Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. The staff position provides additional guidance for estimating fair value in accordance with Statement No. 157 when the volume and level of activity for the asset or liability have significantly decreased. The staff position, which is effective for our fiscal year ending June 30, 2009, did not have an impact on our results of operations or financial position.

In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 115-2 and FAS 124-2, entitled Recognition and Presentation of Other-Than-Temporary Impairments. The staff position provides additional guidance for the presentation and disclosure of other-than-temporary impairments on debt and equity securities. The staff position, which is effective for our fiscal year ending June 30, 2009, did not have an impact on our results of operations or financial position.

In May, 2009, the Financial Accounting Standards Board issued Statement No. 165, entitled Subsequent Events. Statement No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. Statement No. 165 requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for the date. We adopted Statement No. 165 as of June 30, 2009, and as a result of adoption there was no impact on our results of operations or financial position.

Recently Issued Pronouncements

In February, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. 157-2, entitled Effective Date of Financial Accounting Standards Board Statement No. 157, which delays the effective date of Statement No. 157 for one year for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis. This staff position, which shall be effective for our quarter ending September 30, 2009, will not have a material impact on our results of operations or financial position.

In December, 2008, The Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 132(R)-1, entitled Employer's Disclosures about Postretirement Benefit Plan Assets, which amends Financial Accounting Standards Board Statement 132(R), entitled Employers' Disclosures about Pensions and Other Postretirement Benefits, to increase transparency surrounding the types of assets and risks associated with a defined benefit pension or other postretirement plan. Statement 132(R), as amended, will require employers to provide additional disclosure surrounding investment strategies, major categories of plan assets, and valuation techniques used to measure the fair value of plan assets. The staff position, which shall be effective for our fiscal year ending June 30, 2010, will not have an impact on our results of operations or financial position.

In April, 2009, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 107-1 and APB 28-1, entitled Interim Disclosures about Fair Value of Financial Instruments. The staff position amends Financial Accounting Standards Board Statement No. 107, Disclosures about Fair Value of Financial Instruments and Accounting Principles Board Opinion No. 28, entitled Interim Financial Reporting, to require disclosure about the fair value of financial instruments at interim reporting periods. The staff position, which shall be effective for our quarter ending September 30, 2009, will not have an impact on our results of operations or financial position.

(3) Asset Retirement Obligations

Legal obligations

As required by Financial Accounting Standards Board Statement No. 143, entitled Accounting for Asset Retirement Obligations, and Financial Accounting Standards Interpretation No. 47, entitled Accounting for Conditional Asset Retirement Obligations, as of June 30, 2009 and 2008 we have accrued liabilities and related assets, net of accumulated depreciation, relative to the legal obligation to retire certain gas wells, storage tanks, mains and services. For asset retirement obligations related to regulated assets, accretion of the liability and depreciation of the asset retirement costs are recorded as regulatory assets, pursuant to Statement No. 71, as we recover the cost of removing our regulated assets through our depreciation rates.

The following is a summary of our asset retirement obligations and related assets (net of accumulated depreciation), reflected on the accompanying Consolidated Balance Sheets under the captions asset retirement obligations and other, and property, plant and equipment, respectively:

($000)	Asset Retirement Obligations	Net Assets
As of June 30, 2007	1,466	32
Accretion	111	—
Depreciation	—	(2)
Change in obligations	23	23
As of June 30, 2008	1,600	53
Accretion	120	—
Depreciation	—	(18)
Change in obligations	(50)	(29)
As of June 30, 2009	1,670	6

We have an additional asset retirement obligation relative to the retirement of wells located at our underground natural gas storage facility. Since we expect to utilize the storage facility as long as we provide natural gas to our customers, we have determined the underlying asset has an indeterminate life. Therefore, we have not recorded a liability associated with the cost to retire the asset, pursuant to Interpretation No. 47.

Non-legal obligations

In accordance with established regulatory practices, we accrue costs of removal on long-lived assets through depreciation expense if we believe removal of the assets at the end of their useful life is likely even though such costs do not represent legal obligations under Statement No. 143. In accordance with the provisions of Statement No. 71, we have recorded approximately $304,000 and $615,000 of such accrued cost of removal as regulatory liabilities on the accompanying Consolidated Balance Sheets as of June 30, 2009 and 2008, respectively.

(4) Income Taxes

We provide for income taxes on temporary differences resulting from the use of alternative methods of income and expense recognition for financial and tax reporting purposes. The differences result primarily from the use of accelerated tax depreciation methods for certain properties versus the straight-line depreciation method for financial reporting purposes, differences in recognition of purchased gas costs and certain accruals which are not currently deductible for income tax purposes. Investment tax credits were deferred for certain periods prior to fiscal 1987 and are being amortized to income over the estimated useful lives of the applicable properties. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The current portion of the net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in deferred credits and other on the accompanying Consolidated Balance Sheets. The temporary differences which gave rise to the net accumulated deferred income tax liability for the periods are as follows:

($000)	**2009**	2008
Deferred Tax Liabilities		
Accelerated depreciation	**25,650**	23,251
Deferred gas costs	**895**	1,751
Pension	—	515
Regulatory assets – loss on extinguishment of debt	**891**	964
Regulatory assets – asset retirement obligations	**556**	513
Regulatory assets – unrecognized accrued pension	**2,775**	1,343
Other	**424**	445
Total	**31,191**	28,782
Deferred Tax Assets		
Alternative minimum tax credits	—	172
Regulatory liabilities	**649**	815
Investment tax credits	**55**	68
Reserve for bad debt	**311**	177
Asset retirement obligations	**572**	545
Accrued personal leave	**221**	227
Section 263(a) capitalized costs	**64**	113
Pension	**543**	—
Other	**424**	605
Total	**2,839**	2,722
Net accumulated deferred income tax liability	**28,352**	26,060

The components of the income tax provision are comprised of the following for the years ended June 30:

($000)	**2009**	2008	2007
Components of Income Tax Expense			
Current			
Federal	**560**	1,158	494
State	**255**	395	213
Total	**815**	1,553	707
Deferred	**2,193**	2,594	2,450
Income tax expense	**3,008**	4,147	3,157

Reconciliation of the statutory federal income tax rate to the effective income tax rate is shown in the table below:

	2009	2008	2007
Statutory federal income tax rate	**34.0%**	34.0%	34.0%
State income taxes, net of federal benefit	**4.0**	4.0	4.6
Amortization of investment tax credits	**(0.4)**	(0.3)	(0.5)
Other differences, net	**(1.0)**	—	(0.8)
Effective income tax rate	**36.6%**	37.7%	37.3%

In July, 2006, the Financial Accounting Standards Board issued Interpretation No. 48, to clarify the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with Statement No. 109. Interpretation No. 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Interpretation No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

The liability for unrecognized tax benefits expected to be recognized within the next twelve months has partially offset our prepaid income taxes and been presented in prepayments on the Consolidated Balance Sheets. The liability for unrecognized tax benefits not expected to be recognized within the next twelve months has been presented in asset retirement obligations and other on the Consolidated Balance Sheets. Interest and penalties on tax uncertainties are classified in income tax expense in the Consolidated Statements of Income.

The amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $149,000. We accrued interest of $60,000 on unrecognized tax positions, of which $14,000 and $18,000 was recognized in the 2009 and 2008 Consolidated Statements of Income, respectively.

In fiscal 2008, we filed a method change with the Internal Revenue Service related to the timing of deducting certain expenses. During fiscal 2009 we received approval for the method change. As a result of the method change, our liability for unrecognized tax positions decreased $265,000, of which $45,000 represented interest previously accrued on the unrecognized tax position and $220,000 represented deferred taxes on the unrecognized tax position. It is reasonably possible that there will be additional changes to the unrecognized tax benefits within the next twelve months. However, it is not expected that such change will have a significant impact on our results of operations or financial position.

The following is a tabular reconciliation of our unrecognized tax benefits:

($000)	**2009**	2008
Beginning Balance	**653**	668
Gross increases		
Tax positions in prior period	—	1
Tax positions in current period	—	102
Gross decreases		
Tax positions in prior period	**(229)**	(102)
Lapse of statute of limitations	**(46)**	(16)
Ending Balance	**378**	653

We file income tax returns in the federal and Kentucky jurisdictions. Tax years previous to June 30, 2006 and June 30, 2005 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(5) Employee Benefit Plans

(a) Defined Benefit Retirement Plan We have a trusteed, noncontributory, defined benefit pension plan covering all eligible employees hired prior to May 9, 2008. Retirement income is based on the number of years of service and annual rates of compensation. The Company historically makes annual contributions equal to the amounts necessary to fund the plan adequately. Due to the conditions in the debt and equity markets, we experienced a decline in the value of the assets held by our defined benefit pension plan and thus we contributed $2,677,000 to the plan in fiscal 2009.

Statement No. 158 requires employers who sponsor defined benefit plans to recognize the funded status of a defined benefit pension plan on the statement of financial position and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. Statement No. 71 provides that regulated entities can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on Financial Accounting Standards Board Statement No. 87, entitled Employers' Accounting for Pensions, which was amended by Statement No. 158. The Kentucky Public Service Commission has been clear and consistent with its historical treatment of such rate recovery; therefore, we have recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the defined benefit plan that is expected to be recovered through future rates. The regulatory asset is adjusted annually as prior service cost and actuarial losses are recognized in net periodic benefit cost.

Our obligations and the funded status of our plan, measured at June 30, 2009 and March 31, 2008, respectively, are as follows:

($000)	**2009**	2008
Change in Benefit Obligation		
Benefit obligation at beginning of year	**12,773**	13,277
Service cost	**677**	749
Interest cost	**810**	746
Actuarial (gain) loss	**328**	(894)
Amendments	—	(3)
Benefits paid	**(902)**	(1,102)
Change in measurement date	**373**	—
Benefit obligation at end of year	**14,059**	12,773
Change in Plan Assets		
Fair value of plan assets at beginning of year	**14,197**	14,229
Actual return on plan assets	**(2,343)**	325
Employer contributions	**2,677**	745
Benefits paid	**(902)**	(1,102)
Fair value of plan assets at end of year	**13,629**	14,197
Recognized Amounts		
Projected benefit obligation	**(14,059)**	(12,773)
Plan assets at fair value	**13,629**	14,197
Funded status	**(430)**	1,424

	2009	2008
Net amount recognized as prepaid (accrued) benefit costs on the Consolidated Balance Sheets	**(430)**	1,424
Items Not Yet Recognized as a Component of Net Periodic Benefit Costs		
Prior service cost	**(749)**	(857)
Net loss	**8,058**	4,395
Amounts recognized as regulatory assets	**7,309**	3,538

The accumulated benefit obligation was $12,682,000 and $11,679,000 for 2009 and 2008, respectively.

($000)	2009	2008	2007
Components of Net Periodic Benefit Cost			
Service cost	**677**	749	715
Interest cost	**810**	745	700
Expected return on plan assets	**(1,010)**	(988)	(995)
Amortization of unrecognized net loss	**217**	250	233
Amortization of prior service cost	**(86)**	(86)	(86)
Net periodic benefit cost	**608**	670	567
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	**6.25**	6.50	5.80
Rate of compensation increase	**4.0**	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	**6.50**	5.80	5.80
Expected long-term return on plan assets	**7.0**	7.0	8.0
Rate of compensation increase	**4.0**	4.0	4.0

Our expected long-term rate of return on pension plan assets is based on our targeted asset allocation assumption of approximately 65% equity investments and approximately 35% fixed income investments and the market-related value of plan assets. The market-related value of plan assets is based upon the fair value of the plan assets.

Plan Assets

Our pension plan weighted-average asset allocations as of June 30, 2009 and March 31, 2008, the plan's measurement date, by asset category are as follows:

	2009	2008
Equity securities	**73%**	63%
Fixed income securities	**22**	30
Other	**5**	7
	100%	100%

Our equity investment target of approximately 65% includes allocations to domestic, international and emerging markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We expect to contribute $500,000 to the pension plan in 2010.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

($000)

2010	781
2011	510
2012	980
2013	1,578
2014	886
2015 – 2019	6,947

Effective May 9, 2008, any employees hired on and after that date were not eligible to participate in our defined benefit pension plan. Freezing the defined benefit plan for new entrants did not impact the level of benefits for existing participants.

The Statement of Financial Accounting Standards No. 106, entitled Employers' Accounting for Postretirement Benefits, and the Statement of Financial Accounting Standards No. 112, entitled Employers' Accounting for Postemployment Benefits, do not affect us as we do not provide postretirement or postemployment benefits other than the pension plan for retired employees.

(b) Employee Savings Plan We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 4% of the employee's annual compensation. The maximum matching contribution was 3.5% prior to July 1, 2008. Employees hired after May 9, 2008, who are not eligible to participate in the defined benefit pension plan, annually receive a 4% non-elective contribution into their Savings Plan account beginning July 1, 2008. This contribution is discretionary and subject to change with approval from our Board of Directors. For 2009, 2008, and 2007, Delta's Savings Plan expense was $308,000, $281,000 and $256,000, respectively.

(c) Supplemental Retirement Agreement We sponsor a nonqualified defined contribution supplemental retirement agreement for Glenn R. Jennings, Delta's Chairman of the Board, President and Chief Executive Officer. Delta contributes $60,000 annually into an irrevocable trust until Mr. Jennings' retirement. At retirement, the trustee will make annual payments of $100,000 to Mr. Jennings until the trust is depleted. As of June 30, 2009 and 2008, the irrevocable trust assets are $281,000 and $250,000, respectively. These amounts are included in unamortized debt expense and other on the accompanying Consolidated Balance Sheets. Liabilities, in corresponding amounts, are included in asset retirement obligations and other on the accompanying Consolidated Balance Sheets.

(6) Dividend Reinvestment and Stock Purchase Plan

Our Dividend Reinvestment and Stock Purchase Plan ("Reinvestment Plan") provides that shareholders of record can reinvest dividends and also make limited additional investments of up to $50,000 per year in shares of common stock of the Company. Under the Reinvestment Plan we issued 22,287, 18,653, and 21,063 shares in 2009, 2008 and 2007, respectively. We registered 200,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2009 there were 133,811 shares available for issuance.

(7) Note Receivable From Officer Related Party Transaction

Reflected in our 2007 Consolidated Statements of Income is $62,000 of compensation related to the forgiveness of principal on a $160,000 loan made to Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer. We forgave $2,000 of the principal amount for each month of service Mr. Jennings completed through June 30, 2007. Mr. Jennings made monthly interest payments on the note based on an annual interest rate of 6%. We forgave the remaining balance of the note effective June 30, 2007.

(8) Notes Payable

The current available bank line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $3,653,000 and $6,829,000 were borrowed having a weighted average interest rate of 1.8% and 3.21% as of June 30, 2009 and 2008, respectively. The maximum amount borrowed during 2009 and 2008 was $31,325,000 and $26,858,000, respectively. Effective June 30, 2009 the bank line of credit was extended through June 30, 2011. The extension increased the interest rate on the used line of credit from the London Interbank Offered Rate plus .75% to the London Interbank Offered Rate plus 1.5%. The annual cost of the unused bank line of credit is .125%.

(9) Long-Term Debt

In April, 2006, we issued $40,000,000 of 5.75% Insured Quarterly Notes that mature in April, 2021, of which $39,140,000 and $39,642,000 was outstanding as of June 30, 2009 and 2008, respectively. Redemption of up to $25,000 annually will be made on behalf of deceased holders, up to an aggregate of $800,000 annually for all deceased beneficial owners. The 5.75% Insured Quarterly Notes can be redeemed by us with no premium. In the event of default on the Insured Quarterly Notes, the holders are insured for both principal and interest payments. The insurer would continue to pay interest and principal through the maturity of the Insured Quarterly Notes.

In February, 2003 we issued $20,000,000 of 7.00% Debentures that mature in February, 2023, of which $19,659,000 and $19,876,000 was outstanding as of June 30, 2009 and 2008, respectively. Redemption of up to $25,000 annually will be made on behalf of individual deceased holders, up to an aggregate of $400,000 annually for all deceased beneficial owners. There is no premium to redeem the Debentures.

We amortize debt issuance expenses over the life of the related debt on a straight-line basis, which approximates the effective yield method. At June 30, 2009 and 2008, the unamortized balance was $4,736,000 and $5,123,000, respectively. Loss on extinguishment of debt of $2,348,000 and $2,539,000 included in the above has been deferred and is being amortized over the term of the related debt consistent with regulatory treatment.

The current portion of long-term debt of $1,200,000 represents the maximum aggregate principal amounts which can be paid to deceased beneficial owners. Therefore, the maximum maturities over the next five years are $1,200,000 each year. The Insured Quarterly Notes and Debentures do not have any sinking fund requirements.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(10) Fair Values of Financial Instruments

The fair value of our long-term debt is estimated using discounted cash flow analysis, based on our current incremental borrowing rates for similar types of borrowing arrangements. The fair value of our long-term debt at June 30, 2009 and 2008 was estimated to be $52,633,000 and $55,164,000, respectively. The carrying amounts on the accompanying Consolidated Balance Sheets as of June 30, 2009 and 2008 are $58,799,000 and $59,518,000, respectively.

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value.

(11) Operating Leases

We have no non-cancellable operating leases. Our operating leases relate primarily to well and compressor station site leases and are cancellable at our option. Rental expense under operating leases was $78,000 for each of the three years ending June 30, 2009, 2008 and 2007.

(12) Commitments and Contingencies

We have entered into forward purchase agreements beginning in July, 2009 and expiring at various dates through October, 2011. These agreements require us to purchase minimum amounts of natural gas throughout the term of the agreements. These agreements are established in the normal course of business to ensure adequate gas supply to meet our customer's gas requirements. These agreements have aggregate minimum purchase obligations of $3,765,000 and $143,000 for our fiscal years ended June 30, 2010 and 2011, respectively.

We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $2.9 million would be paid in addition to continuation of specified benefits for up to five years.

We are not a party to any material pending legal proceedings.

(13) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

On April 20, 2007, we filed a request for increased rates with the Kentucky Public Service Commission. This general rate case, Case No. 2007-00089, requested an annual revenue increase of approximately $5,642,000, an increase of 9.3%. The rate case requested a return on common equity of 12.1%. During October, 2007, we negotiated a settlement with the Kentucky Attorney General regarding this rate case. The settlement agreement provided for $3,920,000 of additional annual revenues, and stipulated for settlement purposes a 10.5% return on shareholders' equity. The increase in rates was allocated primarily to the monthly customer charge, and therefore the increase in revenue occurred more evenly throughout the year and was not as dependent on customer usage. An order from the Kentucky Public Service Commission was received on October 19, 2007 approving the terms of the settlement with rates effective on or after October 20, 2007.

In July, 2008, the Kentucky Public Service Commission approved in Case No. 2008-00062 our request to implement a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customer's interests by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, including the reimbursement of margins on lost sales and the incentives provided to us.

The Kentucky Public Service Commission has also approved a gas cost recovery clause, which permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs. Although we are not required to file a general rate case to adjust rates pursuant to the gas cost recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual gas costs were incurred. Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible. Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has caused no adverse effect on our operations.

(14) Operating Segments

Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment, and (ii) a non-regulated segment which participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenues recorded under both segments come from the sale or transportation of natural gas. Price risk for the regulated business is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

A single customer, Citizens Gas Utility District, provided \$10,248,000, \$17,087,000 and \$9,843,000 of non-regulated revenues during 2009, 2008 and 2007, respectively. Citizens has decreased their purchases from us, and thus revenues are not expected to continue at historical levels.

In 2009, 2008 and 2007, we purchased approximately 99% of our natural gas from Atmos Energy Marketing and M & B Gas Services.

The segments follow the accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenues and expenses are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Operating expenses, taxes and interest are allocated to the non-regulated segment. Segment information is shown in the following table:

($000)	**2009**	2008	2007
Operating Revenues			
Regulated			
External customers	**64,478**	58,219	53,499
Intersegment	**3,427**	4,019	3,643
Total regulated	**67,905**	62,238	57,142
Non-regulated			
External customers	**41,158**	54,438	44,669
Eliminations for intersegment	**(3,427)**	(4,019)	(3,643)
Total operating revenues	**105,636**	112,657	98,168
Operating Expenses			
Regulated			
Purchased gas	**39,138**	33,493	30,887
Depreciation	**3,737**	4,053	4,579
Other	**15,246**	14,840	13,538
Total regulated	**58,121**	52,386	49,004
Non-regulated			
Purchased gas	**32,940**	43,389	35,173
Depreciation	**118**	118	119
Other	**5,092**	5,119	4,547
Total non-regulated	**38,150**	48,626	39,839
Eliminations for intersegment	**(3,427)**	(4,019)	(3,643)
Total operating expenses	**92,844**	96,993	85,200
Other Income and Deductions, Net			
Regulated	**(50)**	83	134
Non-regulated	**4**	—	—
Total other income and deductions	**(46)**	83	134
Interest Charges			
Regulated	**4,305**	4,556	4,501
Non-regulated	**223**	214	146
Total interest charges	**4,528**	4,770	4,647
Income Tax Expense			
Regulated	**1,949**	2,022	1,349
Non-regulated	**1,059**	2,125	1,808
Total income tax expense	**3,008**	4,147	3,157
Net Income			
Regulated	**3,479**	3,356	2,422
Non-regulated	**1,732**	3,474	2,876
Total net income	**5,211**	6,830	5,298
Assets			
Regulated	**154,297**	163,952	154,029
Non-regulated	**8,208**	6,863	6,372
Total assets	**162,505**	170,815	160,401
Capital Expenditures			
Regulated	**8,422**	5,564	8,083
Non-regulated	**—**	—	—
Total capital expenditures	**8,422**	5,564	8,083

(15) Gas in Storage Inventory Adjustment

We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records. During 2009, after analyzing the storage field data at the end of the injection cycle, we determined that an inventory adjustment was required. We estimated that the adjustment amount would be in the range of $1,350,000 to $1,750,000. Based on the storage field data currently available, we cannot determine if any amount within the range is more likely than any other. The 2009 storage field data suggested that the inventory adjustment is related to a storage well that was identified in 2007 as allowing natural gas to escape. The storage well was remediated during fiscal 2008.

Prior to 2009, sufficient data had not been available to determine the amount of lost gas inventory resulting from the compromised storage well. Prior to 2009, we had no reason to believe this represented a material financial risk to the Company. Our analysis in 2009 indicated a material shortfall of storage gas volumes in comparison with our perpetual inventory records. The 2009 analysis also provided us enough information to estimate a range for adjusting inventory.

During 2009, we recorded a gas in storage inventory adjustment in the amount of $1,350,000. The adjustment is included in operation and maintenance expense in the Consolidated Statements of Income for the year ended June 30, 2009. Any future adjustment to inventory will be determined as additional storage field data is collected and evaluated during future storage injection and withdrawal cycles. The underground storage facility is insured against certain risks such as this, and although we have sought appropriate reimbursement from the insurer we cannot predict the amount of any insurance proceeds. Depending on the outcome of our pursuit of insurance recovery, we will also evaluate whether any unreimbursed gas losses are eligible for regulatory recovery under our gas cost recovery rate mechanism or through other recovery methods. We have not recorded any insurance recovery asset or regulatory asset in the accompanying financial statements; however, to the extent recovery becomes probable, we will evaluate recognition of an asset at that time.

(16) Sale of Property, Plant and Equipment

During 2009, we sold two surplus office buildings for $335,000, which resulted in us recording $156,000 of gains on the sales. The gains are included in operation and maintenance expense in the 2009 Consolidated Statements of Income.

(17) Quarterly Financial Data (Unaudited)

The quarterly data reflects, in the opinion of management, all normal recurring adjustments necessary to present fairly the results for the interim periods.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2009				
September 30	**$ 18,108,090**	**$ 1,570,336**	**$ 273,215**	**$ .08**
December 31	**33,957,969**	**3,313,510** (a)	**1,229,004** (a)	**.37** (a)
March 31	**43,160,716**	**7,919,488**	**4,259,874**	**1.29**
June 30	**10,410,049**	**(10,134)**	**(551,364)**	**(.16)**
Fiscal 2008				
September 30	$ 12,404,170	$ (102,919)	$ (810,945)	$ (.25)
December 31	29,298,418	5,289,682	2,455,285	.75
March 31	48,396,125	9,884,436	5,421,108	1.65
June 30	22,558,404	592,537	(235,580)	(.07)

(a) We recorded a $1,350,000 non-recurring inventory adjustment at December 31, 2008 for our gas in storage, as discussed in Note 15 of the Notes to Consolidated Financial Statements.

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED JUNE 30, 2009, 2008, and 2007

Column A	Column B	Column C Additions		Column D Deductions	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts – Recoveries	Amounts Charged Off Or Paid	Balance at End of Period
Deducted From the Asset to Which it Applies – Allowance for doubtful accounts for the years ended:					
June 30, 2009	$ 465,000	$ 830,588	$ 67,803	$ 544,391	$ 819,000
June 30, 2008	300,000	599,345	64,139	498,484	465,000
June 30, 2007	520,000	272,893	9,824	502,717	300,000

EXHIBIT 12

DELTA NATURAL GAS COMPANY, INC.
COMPUTATION OF THE CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	2009	2008	2007	2006	2005
Earnings					
Net income	**$ 5,210,729**	$ 6,829,868	$ 5,298,347	$ 5,024,635	$ 4,998,619
Provisions for income taxes (a)	**3,008,396**	4,146,900	3,156,700	2,982,900	3,138,800
Fixed charges	**4,553,657**	4,796,489	4,673,261	5,006,608	4,494,445
Total	**$ 12,772,782**	$ 15,773,257	$ 13,128,308	$ 13,014,143	$ 12,631,864
Fixed Charges					
Interest on debt (a)	**$ 4,140,394**	$ 4,383,223	$ 4,260,179	$ 4,704,075	$ 4,229,261
Amortization of debt	**387,263**	387,266	387,082	273,533	236,184
One third of rental expense	**26,000**	26,000	26,000	29,000	29,000
Total	**$ 4,553,657**	$ 4,796,489	$ 4,673,261	$ 5,006,608	$ 4,494,445
Ratio of earnings to fixed charges	**2.80**x	3.29x	2.81x	2.60x	2.81x

(a) Interest accrued on uncertain tax positions, in accordance with Financial Accounting Standards Board Interpretation No. 48, is presented in income taxes on the 2009 and 2008 Consolidated Statements of Income. This interest has been excluded from the determination of fixed charges.

EXHIBIT 21

Subsidiaries of the Registrant

Delgasco, Inc., Enpro, Inc. and Delta Resources, Inc. are wholly-owned subsidiaries of the Registrant, are incorporated in the state of Kentucky and do business under their corporate names.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-130301 of (1) our report dated August 31, 2009 relating to the consolidated financial statements and financial statement schedule of Delta Natural Gas Company, Inc. (the Company) which report expressed an unqualified opinion on the Company's consolidated financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of new accounting standards in 2009 and 2008 and (2) our report dated August 31, 2009 relating to the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2009.

/S/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 31, 2009

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: August 31, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this annual report on Form 10-K of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: August 31, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and
Secretary

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: August 31, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: August 31, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

BATH COUNTY NEWS-OUTLOOK

(DEVOTED TO THE BEST INTERESTS OF BATH COUNTY)

Established 1879

Rates: $2.00 A Year in Kentucky; Elsewhere $2.50

Issued Weekly

Owingsville, Kentucky, Thursday, October 13, 1949

NUMBER 7.

VOLUME SEVENTY-ONE

Gas Franchise Sold Here Today

Franchise Bought By Delta Gas Co. Of Staton; Work To Start Immediately

Copy Of Franchise To Appear Next Week

At a public sale held this morning
t 10 a. m. at the door of the City
Hall here, City Clerk Harold Rey-
nolds sold a natural gas franchise for
the City of Owingsville to the Delta
Natural Gas Company of Staton, Ky.,
for a price of $50.00.

The franchise and sale to the Stan-
ton Company is expected to be ap-
proved at a regular meeting tonight
of the City Council.

Harrison Peet, president of the Del-
ta Gas Company, personally made
the bids for his company. He agreed
to the terms of the franchise, which
states that work on the supplying of
natural gas to the City of Owings-
ville shall begin immediaely in order
to supply the residents of the city as
soon as possible. There is a possibili-
ty of having part of the city ready
for service by December, and the en-
tire city supplied by next spring.

The use of natural gas will be a
long sought-after advantage to Ow-
ingsville, and is a big step forward
in the progress of the city, giving
it all the utility advantages of the
larger cities—electricity, water and
gas.

The gas is expected to reach Ow
ingsville from a hookup with th
main 26-inch line at Olympic
Springs. Upon reaching Owingsvill
mains will be laid to accomoda
every home inside the City limits.

All that will be required of t
property owner will be to pipe fr
the meter, which will be on his
He will also be required to pa
$5.00 deposit fee as a security
posit, just is required for electi
service.

As to the cost of gas offi
state: "The Louisville Gas and
tric Company found after exte
research that natural gas used
heating and cooking costs ap
mately 50 per cent less than o
30 per cent less than coal, mak
large savings to the users of n
gas."

A copy of the complete fr
will appear in next weeks' is
this paper for the public to s
read.

1964 Board/Management

Seated - **Harrison D. Peet**, Chairman and President
Standing left to right:
William A. Finnell - Director, **Ollie Myers** - Berea Manager,
John D. Harrison - Vice President, **Donald Crowe** - Director Delta Stanton,
Claude Killpatrick - Director, **Roger A. Byron** - Director and Attorney,
Arthur E. Walker - Director, **Virgil E. Scott** - Secretary and Treasurer

In 1964, Harry Peet, Jr. died. The elder Peet had been instrumental in helping his son found the company and had advised him over the years on the job of running his own business. One of the things his father told him was …

"You take good care of Delta and she'll take good care of you."

The following year, Delta's gross annual revenue exceeded $1 million for the first time.

Board of Directors

Left to right, standing:

Billy Joe Hall (a) Investment Representative, LPL Financial Services (retail investments), Mount Sterling, Kentucky

Lewis N. Melton (b)* (c) Civil Engineer, Vaughn & Melton Consulting Engineers, Inc. (consulting engineering), Middlesboro, Kentucky

Michael R. Whitley (b) (c) Lead Director; Retired Vice Chairman of the Board, President and Chief Operating Officer, LG & E Energy Corp. (diversified utility), Louisville, Kentucky

Michael J. Kistner (a)* (c) Consultant, MJK Consulting (financial consulting), Louisville, Kentucky

Arthur E. Walker, Jr. (b) President, The Walker Company (general and highway construction), Mount Sterling, Kentucky

Left to right, sitting:

Lanny D. Greer (a) Chairman of the Board and President, First National Financial Corporation and First National Bank (commercial banking), Manchester, Kentucky

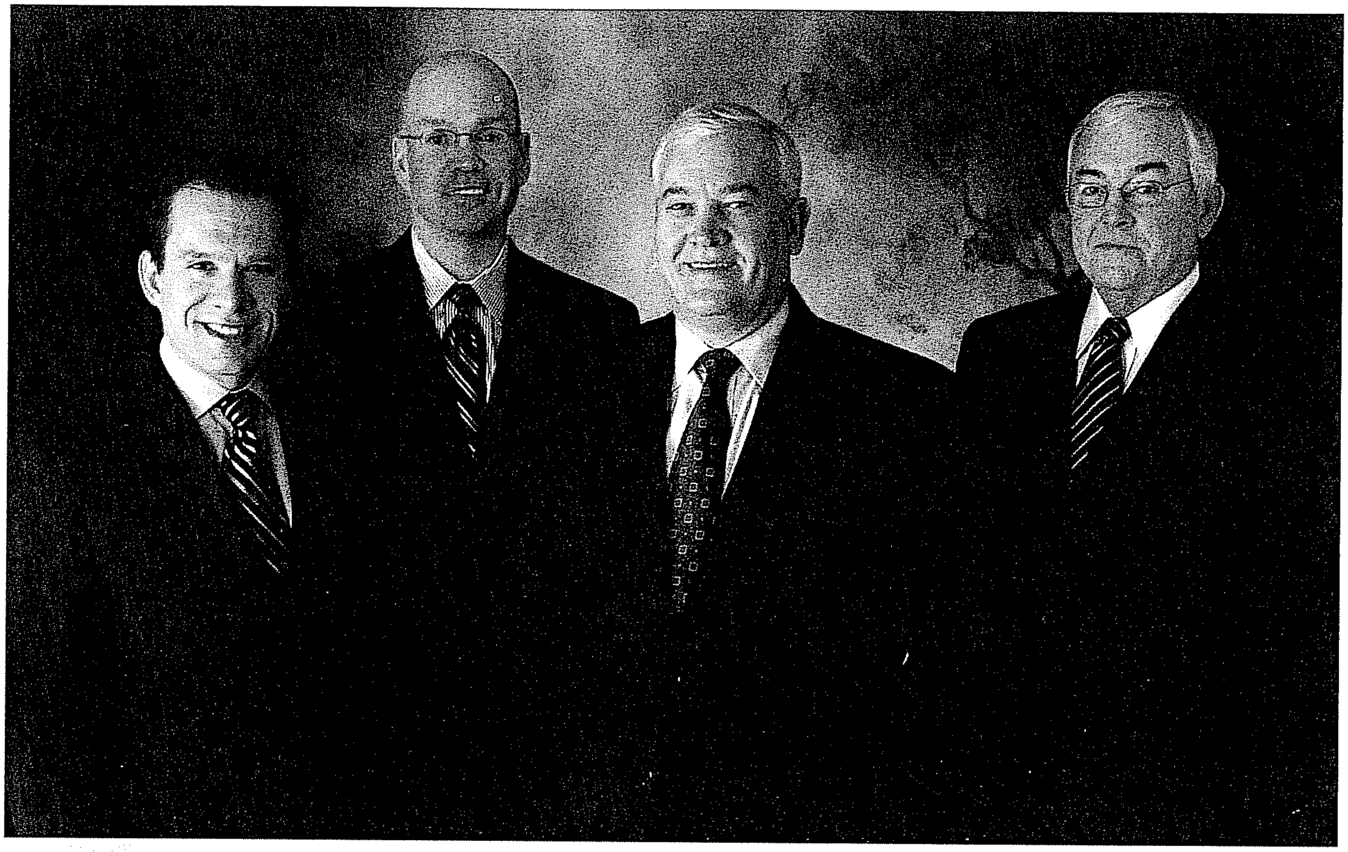
Linda K. Breathitt (a) Energy Consultant; Former Senior Energy Advisor, Thelen Reid Brown Raysman & Steiner LLP (law firm); Former Commissioner, Federal Energy Regulatory Commission, Washington, D.C.

Harrison D. Peet Director Emeritus; Retired Chairman of the Board, President and Chief Executive Officer

Glenn R. Jennings (c)* Chairman of the Board, President and Chief Executive Officer

(a) Member of Audit Committee
(b) Member of Corporate Governance and Compensation Committee
(c) Member of Executive Committee
*Committee Chair

Officers



Left to right:

John B. Brown Chief Financial Officer, Treasurer and Secretary
Brian S. Ramsey Vice President - Transmission and Gas Supply
Glenn R. Jennings Chairman of the Board, President and Chief Executive Officer
Johnny L. Caudill Vice President - Distribution

Corporate Information

SHAREHOLDERS' INQUIRIES
Communications regarding stock transfer requirements, lost certificates, changes of address or other items may be directed to Computershare Investor Services, LLC, the Transfer Agent and Registrar. Communications regarding dividends, the above items or any other shareholder inquiries may be directed to: Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391, email: ebennett@deltagas.com.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
Deloitte & Touche LLP
Suite 1900
250 East Fifth Street
Cincinnati, Ohio 45202

TRUSTEE AND INTEREST PAYING AGENT FOR DEBENTURES

5.75% due 2021; 7% due 2023

The Bank of New York Trust Company, N.A.
525 Vine Street, Suite 900
Cincinnati, OH 45202

DISBURSEMENT AGENT, TRANSFER AGENT AND REGISTRAR FOR COMMON SHARES;
DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN ADMINISTRATOR AND AGENT
Computershare Investor Services, LLC
P.O. Box 43036
Providence, RI 02940-3036
1-888-294-8217

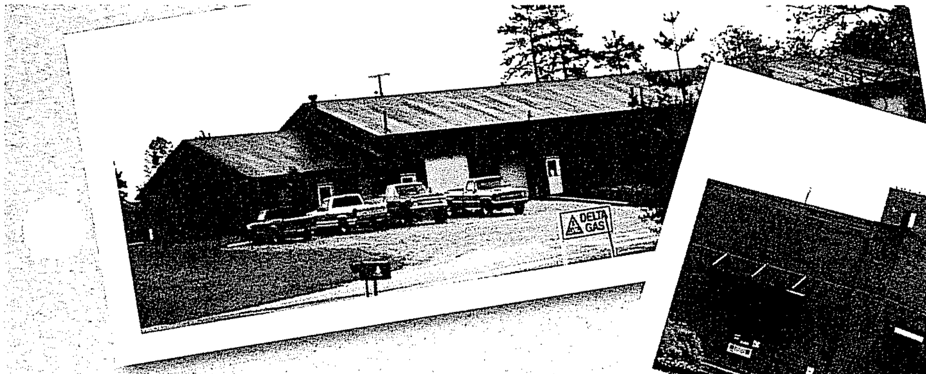
2009 ANNUAL REPORT
This annual report and the financial statements contained herein are submitted to the shareholders of the Company for their general information and not in connection with any sale or offer to sell, or solicitation of any offer to buy, any securities.

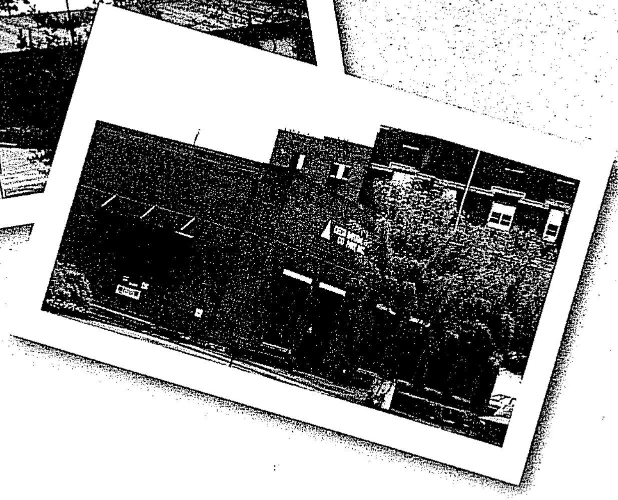
2009 ANNUAL MEETING
The annual meeting of shareholders of the Company will be held at the General Office of the Company in Winchester, Kentucky on November 19, 2009, at 10:00 a.m. Proxies for the annual meeting will be requested from shareholders when notice of meeting, proxy statement and form of proxy are mailed on or about October 13, 2009.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN
This plan provides shareholders of record with a convenient way to acquire additional shares of the Company's common stock without paying brokerage fees. Participants may reinvest their dividends and make optional cash payments to acquire additional shares. Computershare Investor Services, LLC administers the Plan and is the agent for the participants. For more information, inquiries may be directed to Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391, e-mail: ebennett@deltagas.com.

DIVIDEND

Delta Natural Gas Company, Inc. is proud to sponsor Defend My Dividend, a national grassroots advocacy campaign that gives utility investors a powerful and unified voice with a single mission: to make permanent the current 15 percent dividend tax rate beyond 2010. The campaign is sponsored by various associations, organizations and companies, with the support of the their members, employees, retirees and shareholders. For more information, visit www.DefendMyDividend.org.





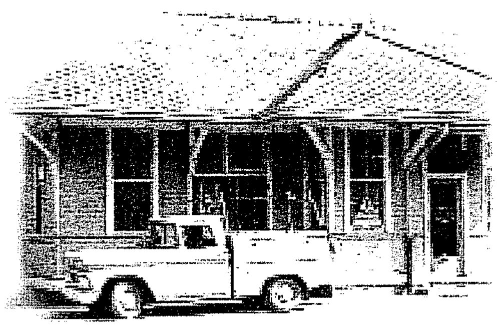
"There were people who questioned us, people who said,
'What are you fellows doing? It's foolish to try to do this'...

We never doubted we could do it –
we had confidence in our people."

H.D. Peet

Founder & Director Emeritus


Quality Service Since 1949 ...



Delta Natural Gas Company, Inc.

3617 Lexington Road
Winchester, Kentucky 40391
Phone: 859.744.6171 Fax: 859.744.6552
www.deltagas.com

Cover art by Bill Berryman, 1986

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to _______

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact Name of Registrant as Specified in its Charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of Principal Executive Offices)	40391 (Zip Code)

859-744-6171
(Registrant's Telephone Number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. As of September 30, 2009, Delta Natural Gas Company, Inc. had 3,323,385 shares of Common Stock outstanding.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(UNAUDITED)

	Three Months Ended September 30,		Twelve Months Ended September 30,	
	2009	2008	2009	2008
OPERATING REVENUES	$ 8,130,950	$ 18,108,090	$ 95,659,684	$ 118,361,037
OPERATING EXPENSES				
Purchased gas	$ 3,484,168	$ 12,323,096	$ 63,238,703	$ 81,296,282
Operation and maintenance	3,168,005	2,826,055	15,372,236	14,058,527
Depreciation and amortization	984,493	949,903	3,889,689	3,862,020
Taxes other than income taxes	453,744	438,700	1,895,651	1,807,218
Total operating expenses	$ 8,090,410	$ 16,537,754	$ 84,396,279	$ 101,024,047
OPERATING INCOME	$ 40,540	$ 1,570,336	$ 11,263,405	$ 17,336,990
OTHER INCOME AND DEDUCTIONS, NET	55,303	(8,638)	17,522	60,681
INTEREST CHARGES	1,045,860	1,145,967	4,427,550	4,707,394
NET INCOME (LOSS) BEFORE INCOME TAXES	$ (950,017)	$ 415,731	$ 6,853,377	$ 12,690,277
INCOME TAX EXPENSE (BENEFIT)	(387,013)	142,516	2,478,866	4,776,250
NET INCOME (LOSS)	$ (563,004)	$ 273,215	$ 4,374,511	$ 7,914,027
BASIC AND DILUTED EARNINGS (LOSS) PER COMMON SHARE	$ (.17)	$ .08	$ 1.32	$ 2.41
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (BASIC AND DILUTED)	3,320,006	3,297,671	3,311,596	3,290,273
DIVIDENDS DECLARED PER COMMON SHARE	$ .325	$ .32	$ 1.285	$ 1.25

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	September 30, 2009	June 30, 2009	September 30, 2008
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 107,626	$ 122,589	$ 885,554
Accounts receivable, less accumulated allowances for doubtful accounts of $669,000, $819,000 and $409,000, respectively	3,699,947	4,085,867	8,969,495
Gas in storage, at average cost	13,004,542	9,746,768	25,758,024
Deferred gas costs	2,629,270	2,356,943	8,101,290
Materials and supplies, at average cost	577,794	662,805	577,757
Prepayments	6,815,614	2,415,527	3,580,039
Total current assets	$ 26,834,793	$ 19,390,499	$ 47,872,159
PROPERTY, PLANT AND EQUIPMENT	$ 200,399,504	$ 199,254,216	$ 194,253,594
Less-Accumulated provision for depreciation	(71,388,325)	(70,616,271)	(68,543,406)
Net property, plant and equipment	$ 129,011,179	$ 128,637,945	$ 125,710,188
OTHER ASSETS			
Cash surrender value of officers' life insurance	$ 432,752	$ 412,661	$ 444,312
Prepaid pension cost	—	—	1,829,872
Regulatory assets	11,364,201	11,394,844	7,632,561
Unamortized debt expense and other	2,648,411	2,669,346	2,774,096
Total other assets	$ 14,445,364	$ 14,476,851	$ 12,680,841
Total assets	$ 170,291,336	$ 162,505,295	$ 186,263,188

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	September 30, 2009	June 30, 2009	September 30, 2008
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 5,332,896	$ 4,691,152	$ 11,076,760
Notes payable	9,595,840	3,653,103	24,698,334
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	1,271,726	983,376	1,230,580
Customers' deposits	493,441	508,209	490,869
Accrued interest on debt	853,515	857,810	862,003
Accrued vacation	724,085	712,216	729,741
Deferred income taxes	724,768	814,549	1,628,913
Other	495,695	487,925	414,047
Total current liabilities	$ 20,691,966	$ 13,908,340	$ 42,331,247
LONG-TERM DEBT	$ 57,391,000	$ 57,599,000	$ 58,242,000
LONG-TERM LIABILITIES			
Deferred income taxes	$ 30,633,770	$ 27,537,908	$ 24,516,681
Investment tax credits	136,850	144,500	169,475
Regulatory liabilities	1,517,776	1,710,099	1,948,841
Accrued pension	190,186	430,095	—
Asset retirement obligations and other	2,241,908	2,176,171	2,193,725
Total long-term liabilities	$ 34,720,490	$ 31,998,773	$ 28,828,722
COMMITMENTS AND CONTINGENCIES (Note 8)			
Total liabilities	$ 112,803,456	$ 103,506,113	$ 129,401,969
SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value, 20,000,000 shares authorized, 3,323,385, 3,318,046 and 3,301,117 shares outstanding at September 30, 2009, June 30, 2009 and September 30, 2008, respectively)	$ 3,323,385	$ 3,318,046	$ 3,301,117
Premium on common shares	44,590,761	44,465,601	44,106,021
Retained earnings	9,573,734	11,215,535	9,454,081
Total shareholders' equity	$ 57,487,880	$ 58,999,182	$ 56,861,219
Total liabilities and shareholders' equity	$ 170,291,336	$ 162,505,295	$ 186,263,188

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(UNAUDITED)

	Three Months Ended September 30,		Twelve Months Ended September 30,	
	2009	2008	2009	2008
COMMON SHARES				
Balance, beginning of period	$ 3,318,046	$ 3,295,759	$ 3,301,117	$ 3,281,814
Issuance of common shares	5,339	5,358	22,268	19,303
Balance, end of period	$ 3,323,385	$ 3,301,117	$ 3,323,385	$ 3,301,117
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 44,465,601	$ 43,967,481	$ 44,106,021	$ 43,620,293
Issuance of common shares	125,160	138,540	484,740	485,728
Balance, end of period	$ 44,590,761	$ 44,106,021	$ 44,590,761	$ 44,106,021
RETAINED EARNINGS				
Balance, beginning of period	$ 11,215,535	$ 10,330,345	$ 9,454,081	$ 5,746,715
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	—	(94,300)	—	(94,300)
Balance, beginning of period, as adjusted	$ 11,215,535	$ 10,236,045	$ 9,454,081	$ 5,652,415
Net income (loss)	(563,004)	273,215	4,374,511	7,914,027
Dividends declared on common shares (See Consolidated Statements of Income (Loss) for rates)	(1,078,797)	(1,055,179)	(4,254,858)	(4,112,361)
Balance, end of period	$ 9,573,734	$ 9,454,081	$ 9,573,734	$ 9,454,081
COMMON SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 58,999,182	$ 57,593,585	$ 56,861,219	$ 52,648,822
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	—	(94,300)	—	(94,300)
Balance, beginning of period, as adjusted	$ 58,999,182	$ 57,499,285	$ 56,861,219	$ 52,554,522
Net income (loss)	(563,004)	273,215	4,374,511	7,914,027
Issuance of common shares	130,499	143,898	507,008	505,031
Dividends on common shares	(1,078,797)	(1,055,179)	(4,254,858)	(4,112,361)
Balance, end of period	$ 57,487,880	$ 56,861,219	$ 57,487,880	$ 56,861,219

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Twelve Months Ended September 30, 2009	Twelve Months Ended September 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss)	$ (563,004)	$ 273,215	$ 4,374,511	$ 7,914,027
Adjustments to reconcile net income (loss) to net cash from operating activities				
Depreciation and amortization	1,111,278	1,076,688	4,396,831	4,362,955
Provision for inventory adjustment	—	—	1,350,300	—
Deferred income taxes and investment tax credits	2,967,638	61,519	5,041,467	2,726,496
Gain on sale of property, plant and equipment	—	(156,023)	—	(172,978)
Change in cash surrender value of officers' life insurance	(20,091)	—	11,560	(18,704)
Other - net	(135,130)	(185,239)	(373,565)	(355,511)
Decrease (increase) in assets	(7,469,328)	(13,886,063)	20,428,954	(14,825,129)
Increase (decrease) in liabilities	972,154	(1,673,783)	(8,860,213)	3,620,755
Net cash provided by (used in) operating activities	$ (3,136,483)	$ (14,489,686)	$ 26,369,845	$ 3,251,911
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (1,693,479)	$ (2,108,265)	$ (7,710,370)	$ (5,520,984)
Proceeds from sale of property, plant and equipment	28,560	351,384	203,941	634,321
Other	—	—	60,000	—
Net cash used in investing activities	$ (1,664,919)	$ (1,756,881)	$ (7,446,429)	$ (4,886,663)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common stock	$ (1,078,797)	$ (1,055,179)	$ (4,254,858)	$ (4,112,361)
Issuance of common stock	130,499	143,898	507,008	505,031
Repayment of long-term debt	(208,000)	(76,000)	(851,000)	(265,000)
Borrowings on bank line of credit	11,338,876	31,416,621	54,029,312	73,911,126
Repayments of bank line of credit	(5,396,139)	(13,547,078)	(69,131,806)	(67,802,226)
Net cash provided by (used in) financing activities	$ 4,786,439	$ 16,882,262	$ (19,701,344)	$ 2,236,570
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	$ (14,963)	$ 635,695	$ (777,928)	$ 601,818
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	122,589	249,859	885,554	283,736
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 107,626	$ 885,554	$ 107,626	$ 885,554

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Nature of Operations

Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 37,000 customers. Our distribution and transmission systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage.

(2) Basis of Presentation

All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated. In preparation of the consolidated financial statements, we evaluated subsequent events after the balance sheet date of September 30, 2009 through November 5, 2009, the filing date of this Form 10-Q.

All adjustments necessary for a fair presentation of the unaudited results of operations for the three and twelve months ended September 30, 2009 and 2008 are included. All such adjustments are accruals of a normal and recurring nature other than the inventory adjustment discussed in Note 11 to adjust our gas in storage during the quarter ended December 31, 2008. The results of operations for the periods ended September 30, 2009 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve month ended financial information is provided for additional information only. The accompanying consolidated financial statements are unaudited and should be read in conjunction with the financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended June 30, 2009.

Recently Adopted Accounting Standards

In June 2009, the Financial Accounting Standards Board issued Statement No. 168, entitled The FASB Accounting Standards Codification ("Codification") and the Hierarchy of Generally Accepted Accounting Principles ("GAAP"), which establishes the Codification as the single source of authoritative GAAP recognized by the Financial Accounting Standards Board. Securities and Exchange Commission ("SEC") rules and interpretive releases are also sources of authoritative generally accepted accounting principles for SEC registrants. Statement No. 168 was effective for periods ending after September 15, 2009. Statement No. 168 did not change or alter existing GAAP; therefore it did not impact our results of operations, cash flows or financial position. Effective for our quarter ended September 30, 2009, we have adjusted historical GAAP references in our SEC Form 10-Q to reflect accounting guidance references included in the Codification.

Effective July 1, 2009, we adopted Codification Topic 820, entitled Fair Value Measurement and Disclosures, as it relates to nonfinancial assets and nonfinancial liabilities that are measured at fair value on a nonrecurring basis. Our nonfinancial assets and liabilities measured at fair value on a nonrecurring basis consist of our asset retirement obligations, which are measured at fair value only upon initial recognition. The adoption did not have a material impact on our results of operations or financial position.

In August 2009, the Financial Accounting Standards Board issued Accounting Standards Update No. 2009-05, entitled Fair Value Measurements and Disclosures (Topic 820) – Measuring Liabilities at Fair Value. Update No. 2009-05 provides additional guidance in measuring the fair value of liabilities when a lack of observable market information exists to value the liability from an exit price perspective. We adopted the provisions of Update No. 2009-05 effective for our quarter ended September 30, 2009 and the adoption did not impact our results of operations or financial position.

Recently Issued Accounting Standards

In December, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 132(R)-1, entitled Employer's Disclosures about Postretirement Benefit Plan Assets. Upon issuance of the Accounting Standards Codification, the provisions of Staff Position No. FAS 132(R)-1 were superseded and added as pending content to Codification Topic 715-20, entitled Defined Benefit Plans – General. The pending content provides for additional disclosure to increase transparency surrounding the types of assets and risks associated with a defined benefit pension or other postretirement plan. Codification Topic 715-20, as amended, will require employers to provide additional disclosure surrounding investment strategies, major categories of plan assets, and valuation techniques used to measure the fair value of plan assets. The pending content, which shall be effective for our fiscal year ending June 30, 2010, will not have an impact on our results of operations or financial position.

(3) Fair Value Measurements

Pursuant to Codification Topic 820, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although additional fair value measurements are not required, the guidance in Codification Topic 820 applies to other accounting pronouncements that require or permit fair value measurements.

We determine the fair value of financial assets and liabilities based on the following fair value hierarchy, as prescribed by Codification Topic 820, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3 – Unobservable inputs which require the reporting entity to develop its own assumptions.

Our financial assets and liabilities measured at fair value on a recurring basis consist of the assets of our supplemental retirement benefit trust, which is included in unamortized debt expense and other on the Consolidated Balance Sheets. The offsetting liability is included in asset retirement obligations and other on the Consolidated Balance Sheets. Contributions to the trust are presented in other investing activities on the Consolidated Statement of Cash Flows. The liability is not considered a financial liability within the scope of Codification Topic 820. The assets of the trust are recorded at fair value and consist of exchange traded mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the fair value hierarchy. The fair value of the trust assets are as follows:

($000)	September 30, 2009	June 30, 2009	September 30, 2008
Trust assets	310	281	239

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value.

Our Debentures and Insured Quarterly Notes, presented as current portion of long-term debt and long-term debt on the Consolidated Balance Sheets, are stated at historical cost. Fair value of our long-term debt is based on the expected future cash flows of the debt discounted using a credit adjusted risk-free rate. The Insured Quarterly Notes contain insurance that provides for the continuing payment of principal and interest to the holders in the event we default on the Insured Quarterly Notes. Upon default, the insurer would pay interest and principal to the holders through the maturity of the Insured Quarterly Notes and our obligation transfers to the insurer. Therefore, the insurance is not considered in the determination of the fair value of the Insured Quarterly Notes.

	September 30, 2009	
($000)	Carrying Amount	Fair Value
7% Debentures	19,587	19,360
5.75% Insured Quarterly Notes	39,004	34,606

Our nonfinancial assets and nonfinancial liabilities that are measured at fair value on a nonrecurring basis consist of our asset retirement obligations. Our asset retirement obligations are measured at fair value upon initial recognition based on the expected future cash flows of the obligation. Additionally, in the future certain events may require us to evaluate long-lived assets for impairment to determine if their carrying value exceeds their fair value.

Entities are permitted to electively measure many financial instruments and certain other items at fair value. We do not currently have any financial assets or financial liabilities for which the fair value option has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with Codification Topic 820.

(4) Risk Management and Derivative Instruments

To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. We mitigate price risk by efforts to balance supply and demand. None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Codification Topic 815, entitled Derivatives and Hedging.

(5) Unbilled Revenue

We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	September 30, 2009	June 30, 2009	September 30, 2008
Unbilled revenues ($)	1,423	1,386	1,677
Unbilled gas costs ($)	593	519	835
Unbilled volumes (Mcf)	65	55	48

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(6) Defined Benefit Retirement Plan

Net periodic benefit cost for our trusteed, noncontributory defined benefit pension plan for the periods ended September 30 include the following:

($000)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Twelve Months Ended September 30, 2009	Twelve Months Ended September 30, 2008
Service cost	182	169	689	730
Interest cost	214	203	822	762
Expected return on plan assets	(238)	(253)	(996)	(993)
Amortization of unrecognized net loss	124	55	287	242
Amortization of prior service cost	(22)	(22)	(86)	(86)
Net periodic benefit cost	260	152	716	655

(7) Notes Payable

The current available bank line of credit with Branch Banking and Trust Company, is $40,000,000, of which $9,596,000, $3,653,000 and $24,698,000 were borrowed having a weighted average interest rate of 1.8%, 1.8%, and 3.2%, as of September 30, 2009, June 30, 2009 and September 30, 2008, respectively. Effective June 30, 2009, the bank line of credit was extended through June 30, 2011, and the interest rate on the used line of credit was increased from the London Interbank Offered Rate plus .75% to the London Interbank Offered Rate plus 1.5%.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(8) Commitments and Contingencies

We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $2.9 million would be paid in addition to continuation of specified benefits for up to five years.

We are not a party to any material pending legal proceedings.

We have entered into forward purchase agreements beginning in July, 2009 and expiring at various dates through October, 2010. These agreements require us to purchase minimum amounts of natural gas throughout the term of the agreements. These agreements are established in the normal course of business to ensure adequate gas supply to meet our customer's gas requirements. These agreements have aggregate minimum purchase obligations of $1,072,000 and $143,000 for our fiscal years ended June 30, 2010 and 2011, respectively.

(9) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

In October, 2007, we implemented new rates for our regulated customers after approval by the Kentucky Public Service Commission of a settlement agreement we entered into with the Kentucky Attorney General for a rate case we filed with the Kentucky Public Service Commission earlier that year. The settlement agreement provided for a 10.5% return on shareholder's equity and a $3,920,000 increase in annual revenues. The increase in rates was primarily allocated to the monthly customer charge and therefore the increase in revenues occurred more evenly throughout the year and was not as dependent on customer usage.

(10) Operating Segments

Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment that participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the distribution or transportation of natural gas. Price risk for the regulated segment is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2009. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenues and expenses are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Appropriate related operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown in the following table:

($000)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Twelve Months Ended September 30, 2009	Twelve Months Ended September 30, 2008
Operating Revenues				
Regulated				
External customers	5,266	6,649	63,094	59,600
Intersegment	553	762	3,218	4,083
Total regulated	5,819	7,411	66,312	63,683
Non-regulated				
External customers	2,865	11,459	32,566	58,761
Eliminations for intersegment	(553)	(762)	(3,218)	(4,083)
Total operating revenues	8,131	18,108	95,660	118,361
Net Income (Loss)				
Regulated	(822)	(460)	3,117	4,096
Non-regulated	259	733	1,258	3,818
Total net income (loss)	(563)	273	4,375	7,914

(11) Gas In Storage Inventory Adjustment

We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records. During fiscal 2009, after analyzing the storage field data at the end of the injection cycle, we determined that an inventory adjustment was required. We estimated that the adjustment amount would be in the range of $1,350,000 to $1,750,000. Based on the storage field data currently available, we cannot determine if any amount within the range is more likely than any other. The fiscal 2009 storage field data suggested that the inventory adjustment is related to a storage well that was identified in 2007 as allowing natural gas to escape. The storage well was remediated during fiscal 2008.

During fiscal 2009, we recorded a gas in storage inventory adjustment in the amount of $1,350,000. The adjustment is included in operation and maintenance expense in the Consolidated Statements of Income for the twelve months ended September 30, 2009. Any future adjustment to inventory will be determined as additional storage field data is collected and evaluated during future storage injection and withdrawal cycles.

The underground storage facility is insured against certain risks such as this loss. In October, 2009, we received the preliminary findings from the external consultant engaged by the insurance company to review our claim. The preliminary findings challenge our right to recover the full amount of the claim. We disagree with the consultant's preliminary findings and intend to file a rebuttal with the insurance company. We cannot predict the amount of any insurance proceeds.

Depending on the outcome of our pursuit of insurance recovery, we will also evaluate whether any unreimbursed gas losses are eligible for regulatory recovery under our gas cost recovery rate mechanism or through other recovery methods. We have not recorded any insurance recovery asset or regulatory asset in the accompanying consolidated financial statements; however, to the extent recovery becomes probable, we will evaluate recognition of an asset at that time.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE SEPTEMBER 30, 2009 OVERVIEW AND FUTURE OUTLOOK

For the three months ended September 30, 2009, there was a consolidated net loss per share of $.17 compared with net income of $.08 per share for the three months ended September 30, 2008. The decrease is due to a $474,000 decrease in net income for our non-regulated segment and a $362,000 increase in the net loss for the regulated segment.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income (loss) adjusted for non-cash items, including depreciation, amortization, deferred income taxes, gains on the sale of assets and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $9,596,000 at September 30, 2009 compared to $3,653,000 at June 30, 2009 due to gas purchased for storage and capital expenditures. Notes payable decreased to $9,596,000 at September 30, 2009 compared to $24,698,000 at September 30, 2008 due to a 64% decrease in the cost of gas purchased for storage during the three months ended September 30, 2009, as compared to the three months ended September 30, 2008.

Our liquidity is also impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $1,693,000 and $7,710,000 during the three and twelve months ended September 30, 2009, respectively. In periods when cash provided by operating activities is not sufficient to meet our capital requirements, we finance the balance of our capital expenditures on an interim basis through the bank line of credit.

Long-term debt decreased to $57,391,000 at September 30, 2009, compared with $57,599,000 at June 30, 2009 and $58,242,000 at September 30, 2008. The decreases resulted from the redemption of the Debentures and Insured Quarterly Notes, which allow limited redemptions to be made by certain holders or their beneficiaries.

Cash and cash equivalents were $108,000 at September 30, 2009, as compared with $123,000 at June 30, 2009 and $886,000 at September 30, 2008. The changes in cash and cash equivalents are summarized in the following table:

	Three Months Ended September 30,		Twelve Months Ended September 30,	
($000)	2009	2008	2009	2008
Provided by (used in) operating activities	(3,136)	(14,489)	26,369	3,252
Used in investing activities	(1,665)	(1,757)	(7,446)	(4,887)
Provided by (used in) financing activities	4,786	16,882	(19,701)	2,237
Increase (decrease) in cash and cash equivalents	(15)	636	(778)	602

For the three months ended September 30, 2009, cash used in operating activities decreased $11,353,000 (78%). Cash paid for natural gas decreased $21,443,000 due to decreases in both the cost of gas purchased and the quantities purchased. The decrease was partially offset by an $11,906,000 decrease in cash received from customers due to decreases in both sales prices and volumes sold.

For the twelve months ended September 30, 2009, cash provided by operating activities increased $23,117,000 (711%). Cash paid for natural gas decreased $40,359,000 due to decreases in both the cost of gas purchased and the quantities purchased. The decrease was partially offset by a $15,592,000 decrease in cash received from customers due to decreases in both sales prices and volumes sold.

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

For the three months ended September 30, 2009, cash provided by financing activities decreased $12,096,000 due to decreased net borrowings on the bank line of credit.

For the twelve months ended September 30, 2009, cash used in financing activities increased $21,938,000 due to increased net repayments on the bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2010 to be approximately $6.3 million.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that internally generated cash is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $9,596,000 was borrowed at September 30, 2009. The current bank line of credit extends through June 30, 2011.

Our ability to borrow on our bank line of credit is dependent on our compliance with covenants. Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and

- We may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented. We are not aware of any events that would cause us to be in default in fiscal 2010.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices, and we continuously monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our regulated services.

In October, 2007, we implemented new rates for our regulated customers after approval by the Kentucky Public Service Commission of a settlement agreement we entered into with the Kentucky Attorney General for a rate case we filed with the Kentucky Public Service Commission earlier that year. The settlement agreement provided for a 10.5% return on shareholder's equity and a $3,920,000 increase in annual revenues. The increase in rates was primarily allocated to the monthly customer charge, and therefore the increase in revenues occurred more evenly throughout the year and was not as dependent on customer usage.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to "gross margin". With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented in the Consolidated Statements of Income (Loss) is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States. "Gross margin" is a "non-GAAP financial measure", as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3 for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three and twelve months ended September 30, 2009 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

($000)	2009 compared to 2008 Three Months Ended September 30,	Twelve Months Ended September 30,
Increase (decrease) in regulated gross margins		
Gas sales	(81)	(239)
On-system transportation	1	(367)
Off-system transportation	(216)	(401)
Other	(8)	5
Intersegment elimination (a)	209	865
Total	(95)	(137)
Decrease in non-regulated gross margins		
Gas sales	(784)	(3,471)
Other	(50)	(171)
Intersegment elimination (a)	(209)	(865)
Total	(1,043)	(4,507)
Decrease in consolidated gross margins	(1,138)	(4,644)
Percentage increase (decrease) in regulated volumes		
Gas sales	5	3
On-system transportation	(12)	(16)
Off-system transportation	(23)	(13)
Percentage decrease in non-regulated gas sales volumes	(49)	(31)

(a) Intersegment eliminations represent the transportation fee charged by the regulated segment to the non-regulated segment.

Heating degree days were 101% of normal thirty year average temperatures for the twelve months ended September 30, 2009 as compared with 95% of normal temperatures in 2008. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended September 30, 2009, consolidated gross margins decreased $1,138,000 (20%) due to decreased non-regulated and regulated gross margins of $1,043,000 (51%) and $95,000 (3%), respectively. Our non-regulated gross margins decreased due to a 49% decrease in volumes sold and a 52% decline in sales prices. Non-regulated customers volumes are generally less sensitive to weather. The non-regulated volumes sold decreased due to a decrease in our non-regulated customers' gas requirements, which we attribute primarily to current economic conditions.

For the twelve months ended September 30, 2009, consolidated gross margins decreased $4,644,000 (13%) due to decreased non-regulated and regulated gross margins of $4,507,000 (39%) and $137,000 (1%), respectively. Our non-regulated gross margins decreased due to a 31% decrease in volumes sold and a 20% decline in sales prices. The non-regulated volumes sold decreased due to a decrease in our non-regulated customers' gas requirements, which we attribute primarily to current economic conditions.

Operation and Maintenance

For the three months ended September 30, 2009, operation and maintenance expense increased $342,000 (12%). The increase was primarily due to increased employee benefit expense ($215,000) and increased professional services expense ($113,000).

For the twelve months ended September 30, 2009, operation and maintenance expense increased $1,313,000 (9%). The increase was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 11 of the Notes to Consolidated Financial Statements).

Interest Charges

For the three and twelve months ended September 30, 2009, interest charges decreased $100,000 (9%) and $280,000 (6%), respectively, due to decreases in the average interest rate on our bank line of credit and decreased borrowings on our bank line of credit.

Income Tax Expense (Benefit)

For the three and twelve months ended September 30, 2009, income tax expense (benefit) changed as a result of corresponding changes in net income (loss) before income taxes.

Basic and Diluted Earnings Per Common Share

For the three and twelve months ended September 30, 2009 and 2008, our basic earnings (loss) per common share changed as a result of changes in net income (loss) and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings (loss) per common share and our diluted earnings (loss) per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Accounting Standards Codification Topic 815, entitled Derivatives and Hedging.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balance on our bank line of credit was $9,596,000, $3,653,000 and $24,698,000 on September 30, 2009, June 30, 2009 and September 30, 2008, respectively. The weighted average interest rates on our bank line of credit were 1.8%, 1.8% and 3.2% on September 30, 2009, June 30, 2009 and September 30, 2008, respectively. Based on the amounts of our outstanding bank line of credit on September 30, 2009, June 30, 2009 and September 30, 2008, a one percent (one hundred basis point) increase in our average interest rates would result in a decrease in our annual pre-tax net income of $96,000, $37,000 and $247,000, respectively. Effective June 30, 2009, the bank line of credit was extended through June 30, 2011. The extension increased the interest rate on the used bank line of credit from the London Interbank Offered Rate plus .75% to the London Interbank Offered Rate plus 1.5%.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's ("SEC's") rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of September 30, 2009, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended September 30, 2009 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: November 5, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: November 5, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: November 5, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 32.1

**CERTIFICATION OF THE
CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: November 5, 2009

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: November 5, 2009

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal
Accounting Officer)
(Duly Authorized Officer)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934

November 19, 2009

Date of Report (Date of earliest event reported)

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	0-8788	61-0458329
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	(Zip Code)

859-744-6171

Registrant's telephone number, including area code

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

On November 19, 2009, at the 2009 Annual Meeting of Shareholders of Delta Natural Gas Company, Inc., our shareholders adopted and approved the Delta Natural Gas Company, Inc. Incentive Compensation Plan (the "Plan"), which was previously approved by our Board of Directors on August 21, 2009, subject to shareholder approval. The Plan, which provides for incentive compensation payable in stock, restricted stock and stock bonus awards, was approved and recommended to our Board of Directors by our Corporate Governance and Compensation Committee of the Board of Directors. The Plan, which becomes effective on January 1, 2010, is administered by our Corporate Governance and Compensation Committee, which has complete discretion in determining our employees, officers and outside directors who shall be eligible to participate in the Plan, as well as the type, amount, terms and conditions of each award, subject to the limitations of the Plan.

The purpose of the Plan is to promote our interests and the interests of our shareholders through (a) the attraction and retention of employees and directors essential to our success, and (b) the motivation of employees and directors using performance-related incentives linked to performance goals and the interests of us and our shareholders and (c) enabling such individuals to share in our growth and success.

The number of shares of our common stock which may be issued pursuant to the Plan may not exceed in the aggregate 500,000 shares.

This summary of the Plan is qualified in its entirety by reference to the full text of the Plan, a copy of which is attached as Appendix A to the Company's Definitive Proxy for its 2009 Annual Shareholder Meeting filed with the Securities and Exchange Commission on September 25, 2009. In addition, a more detailed summary of the Plan can be found in such Definitive Proxy Statement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

DELTA NATURAL GAS COMPANY, INC.

Date: November 23, 2009

By: /s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ________

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky (State or other jurisdiction of incorporation or organization)	61-0458329 (I.R.S. Employer Identification No.)
3617 Lexington Road, Winchester, Kentucky (Address of principal executive offices)	40391 (Zip code)

859-744-6171
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date. As of December 31, 2009, Delta Natural Gas Company, Inc. had 3,327,573 shares of Common Stock outstanding.

DELTA NATURAL GAS COMPANY, INC.

INDEX TO FORM 10-Q

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended December 31,		Six Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008	2009	2008
OPERATING REVENUES	$21,114,433	$33,957,969	$29,245,383	$52,066,058	$ 82,816,149	$123,020,587
OPERATING EXPENSES						
Purchased gas	$12,298,555	$24,081,852	$15,782,724	$36,404,948	$ 51,455,406	$ 86,042,694
Operation and maintenance	3,261,750	5,155,649	6,429,754	7,981,705	13,478,337	16,024,446
Depreciation and amortization	982,360	961,383	1,966,853	1,911,286	3,910,666	3,780,114
Taxes other than income taxes	485,758	445,575	939,502	884,275	1,935,834	1,812,515
Total operating expenses	$17,028,423	$30,644,459	$25,118,833	$47,182,214	$ 70,780,243	$107,659,769
OPERATING INCOME	$ 4,086,010	$ 3,313,510	$ 4,126,550	$ 4,883,844	$ 12,035,906	$ 15,360,818
OTHER INCOME AND DEDUCTIONS, NET	26,187	(78,620)	81,489	(87,257)	122,327	(23,136)
INTEREST CHARGES	1,065,162	1,264,211	2,111,022	2,410,177	4,228,501	4,640,742
NET INCOME BEFORE INCOME TAXES	$ 3,047,035	$ 1,970,679	$ 2,097,017	$ 2,386,410	$ 7,929,732	$ 10,696,940
INCOME TAX EXPENSE	1,134,160	741,675	747,146	884,191	2,871,352	4,009,194
NET INCOME	$ 1,912,875	$ 1,229,004	$ 1,349,871	$ 1,502,219	$ 5,058,380	$ 6,687,746
BASIC AND DILUTED EARNINGS PER COMMON SHARE	$ .58	$ .37	$ .41	$ .46	$ 1.53	$ 2.03
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (BASIC AND DILUTED)	3,324,637	3,303,313	3,322,169	3,300,403	3,316,931	3,295,341
DIVIDENDS DECLARED PER COMMON SHARE	$ .325	$ .32	$ .65	$ .64	$ 1.29	$ 1.26

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	December 31, 2009	June 30, 2009	December 31, 2008
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 138,146	$ 122,589	$ 324,863
Accounts receivable, less accumulated allowances for doubtful accounts of $495,000, $819,000, and $852,000, respectively	12,653,512	4,085,867	18,602,820
Gas in storage, at average cost	10,978,247	9,746,768	21,183,038
Deferred gas costs	1,573,758	2,356,943	6,032,930
Materials and supplies, at average cost	525,775	662,805	588,409
Prepayments	5,374,954	2,415,527	4,178,350
Total current assets	$ 31,244,392	$ 19,390,499	$ 50,910,410
PROPERTY, PLANT AND EQUIPMENT	$ 201,406,820	$ 199,254,216	$ 195,391,491
Less-Accumulated provision for depreciation	(72,174,115)	(70,616,271)	(69,259,827)
Net property, plant and equipment	$ 129,232,705	$ 128,637,945	$ 126,131,664
OTHER ASSETS			
Cash surrender value of life insurance	$ 440,746	$ 412,661	$ 384,940
Prepaid pension cost	—	—	1,677,932
Regulatory assets	11,400,086	11,394,844	7,648,521
Unamortized debt expense and other	2,667,245	2,669,346	2,758,250
Total other assets	$ 14,508,077	$ 14,476,851	$ 12,469,643
Total assets	$ 174,985,174	$ 162,505,295	$ 189,511,717

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED BALANCE SHEETS (continued)
(UNAUDITED)

	December 31, 2009	June 30, 2009	December 31, 2008
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 6,292,716	$ 4,691,152	$ 8,868,368
Notes payable	12,015,728	3,653,103	28,652,755
Current portion of long-term debt	1,200,000	1,200,000	1,200,000
Accrued taxes	1,475,910	983,376	1,388,248
Customers' deposits	641,019	508,209	621,511
Accrued interest on debt	854,190	857,810	859,592
Accrued vacation	612,652	712,216	605,410
Deferred income taxes	270,866	814,549	1,628,814
Other	522,249	487,925	470,066
Total current liabilities	$ 23,885,330	$ 13,908,340	$ 44,294,764
LONG-TERM DEBT	$ 57,259,000	$ 57,599,000	$ 58,063,000
LONG-TERM LIABILITIES			
Deferred income taxes	$ 31,058,562	$ 27,537,908	$ 25,695,748
Investment tax credits	129,200	144,500	161,150
Regulatory liabilities	1,419,468	1,710,099	1,872,704
Accrued pension	450,278	430,095	—
Asset retirement obligations and other	2,346,190	2,176,171	2,246,334
Total long-term liabilities	$ 35,403,698	$ 31,998,773	$ 29,975,936
COMMITMENTS AND CONTINGENCIES (Note 8)			
Total liabilities	$ 116,548,028	$ 103,506,113	$ 132,333,700
SHAREHOLDERS' EQUITY			
Common shares ($1.00 par value, 20,000,000 shares authorized; 3,327,573, 3,318,046, and 3,307,446 shares outstanding at December 31, 2009, June 30, 2009 and December 31, 2008, respectively)	$ 3,327,573	$ 3,318,046	$ 3,307,446
Premium on common shares	44,703,270	44,465,601	44,244,428
Retained earnings	10,406,303	11,215,535	9,626,143
Total shareholders' equity	$ 58,437,146	$ 58,999,182	$ 57,178,017
Total liabilities and shareholders' equity	$ 174,985,174	$ 162,505,295	$ 189,511,717

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(UNAUDITED)

	Six Months Ended December 31,		Twelve Months Ended December 31,	
	2009	**2008**	**2009**	**2008**
COMMON SHARES				
Balance, beginning of period	$ 3,318,046	$ 3,295,759	$ 3,307,446	$ 3,286,276
Issuance of common shares	9,527	11,687	20,127	21,170
Balance, end of period	$ 3,327,573	$ 3,307,446	$ 3,327,573	$ 3,307,446
PREMIUM ON COMMON SHARES				
Balance, beginning of period	$ 44,465,601	$ 43,967,481	$ 44,244,428	$ 43,729,714
Issuance of common shares	237,669	276,947	458,842	514,714
Balance, end of period	$ 44,703,270	$ 44,244,428	$ 44,703,270	$ 44,244,428
RETAINED EARNINGS				
Balance, beginning of period	$ 11,215,535	$ 10,330,345	$ 9,626,143	$ 7,184,458
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	—	(94,300)	—	(94,300)
Balance, beginning of period, as adjusted	$ 11,215,535	$ 10,236,045	$ 9,626,143	$ 7,090,158
Net income	1,349,871	1,502,219	5,058,380	6,687,746
Dividends declared on common shares (See Consolidated Statements of Income for rates)	(2,159,103)	(2,112,121)	(4,278,220)	(4,151,761)
Balance, end of period	$ 10,406,303	$ 9,626,143	$ 10,406,303	$ 9,626,143
SHAREHOLDERS' EQUITY				
Balance, beginning of period	$ 58,999,182	$ 57,593,585	$ 57,178,017	$ 54,200,448
Adoption of FASB Statement No. 158 (net of $57,699 of tax)	—	(94,300)	—	(94,300)
Balance, beginning of period, as adjusted	$ 58,999,182	$ 57,499,285	$ 57,178,017	$ 54,106,148
Net income	1,349,871	1,502,219	5,058,380	6,687,746
Issuance of common shares	247,196	288,634	478,969	535,884
Dividends on common shares	(2,159,103)	(2,112,121)	(4,278,220)	(4,151,761)
Balance, end of period	$ 58,437,146	$ 57,178,017	$ 58,437,146	$ 57,178,017

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 1,349,871	$ 1,502,219	$ 5,058,380	$ 6,687,746
Adjustments to reconcile net income to net cash flows from operating activities				
Depreciation and amortization	2,220,423	2,164,858	4,417,807	4,285,720
Deferred income taxes and investment tax credits	2,900,085	1,216,112	3,819,321	2,416,040
Gain on sale of property, plant and equipment	—	(156,023)	—	(172,978)
Provision for inventory adjustment	—	1,350,300	—	1,350,300
Other, net	(264,770)	(317,632)	(370,812)	(440,646)
Change in cash surrender value of life insurance	(28,085)	(59,372)	(55,806)	40,669
Decrease (increase) in assets	(11,895,946)	(18,702,712)	21,099,404	(9,535,363)
Increase (decrease) in liabilities	2,558,305	(3,248,258)	(5,699,587)	145,312
Net cash provided by (used in) operating activities	$ (3,160,117)	$ (16,250,508)	$ 28,268,707	$ 4,776,800
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditures	$ (2,969,045)	$ (3,846,171)	$ (7,349,706)	$ (6,571,402)
Proceeds from sale of property, plant and equipment	94,001	426,206	194,560	538,923
Other	(60,000)	—	(60,000)	—
Net cash used in investing activities	$ (2,935,044)	$ (3,419,965)	$ (7,215,146)	$ (6,032,479)
CASH FLOWS FROM FINANCING ACTIVITIES				
Dividends on common shares	$ (2,159,103)	$ (2,112,121)	$ (4,278,220)	$ (4,151,761)
Issuance of common shares	247,196	288,634	478,969	535,884
Repayment of long-term debt	(340,000)	(255,000)	(804,000)	(339,000)
Borrowings on bank line of credit	21,694,291	53,515,222	42,286,126	76,271,635
Repayment of bank line of credit	(13,331,666)	(31,691,258)	(58,923,153)	(71,417,027)
Net cash provided by (used in) financing activities	$ 6,110,718	$ 19,745,477	$ (21,240,278)	$ 899,731
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	$ 15,557	$ 75,004	$ (186,717)	$ (355,948)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	122,589	249,859	324,863	680,811
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 138,146	$ 324,863	$ 138,146	$ 324,863

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

DELTA NATURAL GAS COMPANY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) Nature of Operations

Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 37,000 customers. Our distribution and transmission systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage.

(2) Basis of Presentation

All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated. All adjustments necessary for a fair presentation of the unaudited results of operations for the three, six and twelve months ended December 31, 2009 and 2008 are included. All such adjustments are accruals of a normal and recurring nature other than the inventory adjustment discussed in Note 11 to adjust our gas in storage during the quarter ended December 31, 2008. In preparation of the consolidated financial statements, we evaluated subsequent events after the balance sheet date of December 31, 2009 through February 8, 2010, the filing date of this Form 10-Q.

The results of operations for the periods ended December 31, 2009 are not necessarily indicative of the results of operations to be expected for the full fiscal year. Because of the seasonal nature of our sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most construction activity and gas storage injections take place during these warmer months. Twelve month ended financial information is provided for additional information only.

The accompanying consolidated financial statements are unaudited and should be read in conjunction with the financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended June 30, 2009.

Recently Adopted Accounting Standards

In June 2009, the Financial Accounting Standards Board issued Statement No. 168, entitled The FASB Accounting Standards Codification ("Codification") and the Hierarchy of Generally Accepted Accounting Principles ("GAAP"), which establishes the Codification as the single source of authoritative GAAP recognized by the Financial Accounting Standards Board. Securities and Exchange Commission ("SEC") rules and interpretive releases are also sources of authoritative generally accepted accounting principles for SEC registrants. Statement No. 168 was effective for periods ending after September 15, 2009. Statement No. 168 did not change or alter existing GAAP, therefore it did not impact our results of operations, cash flows or financial position. We have adjusted historical GAAP references in our SEC filings to reflect accounting guidance references included in the Codification.

Effective July 1, 2009, we adopted Codification Topic 820, entitled Fair Value Measurement and Disclosures, as it relates to nonfinancial assets and nonfinancial liabilities that are measured at fair value on a nonrecurring basis. Our nonfinancial assets and liabilities measured at fair value on a nonrecurring basis consist of our asset retirement obligations, which are measured at fair value only upon initial recognition. The adoption did not have a material impact on our results of operations or financial position.

In August 2009, the Financial Accounting Standards Board issued Accounting Standards Update No. 2009-05, entitled Fair Value Measurements and Disclosures (Topic 820) – Measuring Liabilities at Fair Value. Update No. 2009-05 provides additional guidance in measuring the fair value of liabilities when a lack of observable market information exists to value the liability from an exit price perspective. We adopted the provisions of Update No. 2009-05 effective for our quarter ended September 30, 2009 and the adoption did not impact our results of operations or financial position.

Recently Issued Accounting Standards

In December, 2008, the Financial Accounting Standards Board issued Financial Accounting Standards Board Staff Position No. FAS 132(R)-1, entitled Employer's Disclosures about Postretirement Benefit Plan Assets. Upon issuance of the Accounting Standards Codification, the provisions of Staff Position No. FAS 132(R)-1 were superseded and added as pending content to Codification Topic 715-20, entitled Defined Benefit Plans – General. The pending content provides for additional disclosure to increase transparency surrounding the types of assets and risks associated with a defined benefit pension or other postretirement plan. Codification Topic 715-20, as amended, will require employers to provide additional disclosure surrounding investment strategies, major categories of plan assets, and valuation techniques used to measure the fair value of plan assets. The pending content, which shall be effective for our fiscal year ending June 30, 2010, will not impact our results of operations or financial position.

In January, 2009, the Financial Accounting Standards Board issued Accounting Standards Update No. 2010-06, entitled Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements. Update No. 2010-06 requires entities with fair value measurements to disaggregate major categories of assets and liabilities within the disclosures, disclose transfers between levels within the fair value hierarchy and disclose inputs and valuation techniques for Level 2 and Level 3 fair value measurements. Update No. 2010-06 is effective for reporting periods beginning after December 15, 2009 and will not impact our results of operations or financial position.

(3) Fair Value Measurements

Pursuant to Codification Topic 820, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although additional fair value measurements are not required, the guidance in Codification Topic 820 applies to other accounting pronouncements that require or permit fair value measurements.

We determine the fair value of financial assets and liabilities based on the following fair value hierarchy, as prescribed by Codification Topic 820, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3 – Unobservable inputs which require the reporting entity to develop its own assumptions.

Our financial assets and liabilities measured at fair value on a recurring basis consist of the assets of our supplemental retirement benefit trust, which are included in unamortized debt expense and other on the Consolidated Balance Sheets. The offsetting liability is included in asset retirement obligations and other on the Consolidated Balance Sheets. Contributions to the trust are presented in other investing activities on the Consolidated Statement of Cash Flows. The liability is not considered a financial liability within the scope of Codification Topic 820. The assets of the trust are recorded at fair value and consist of exchange traded mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the fair value hierarchy. The fair value of the trust assets are as follows:

($000)	December 31, 2009	June 30, 2009	December 31, 2008
Trust assets	378	281	272

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value.

Our Debentures and Insured Quarterly Notes, presented as current portion of long-term debt and long-term debt on the Consolidated Balance Sheets, are stated at historical cost. Fair value of our long-term debt is based on the expected future cash flows of the debt discounted using a credit adjusted risk-free rate. The Insured Quarterly Notes contain insurance that provides for the continuing payment of principal and interest to the holders in the event we default on the Insured Quarterly Notes. Upon default, the insurer would pay interest and principal to the holders through the maturity of the Insured Quarterly Notes and our obligation transfers to the insurer. Therefore, the insurance is not considered in the determination of the fair value of the Insured Quarterly Notes.

	December 31, 2009	
($000)	Carrying Amount	Fair Value
7% Debentures	19,510	18,414
5.75% Insured Quarterly Notes	38,949	33,268

Our nonfinancial assets and nonfinancial liabilities that are measured at fair value on a nonrecurring basis consist of our asset retirement obligations. Our asset retirement obligations are measured at fair value upon initial recognition based on the expected future cash flows of the obligation. Additionally, certain future events may require us to evaluate long-lived assets for impairment to determine if their carrying value exceeds their fair value.

Entities are permitted to electively measure many financial instruments and certain other items at fair value. We do not currently have any financial assets or financial liabilities for which the fair value option has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with Codification Topic 820.

(4) Risk Management and Derivative Instruments

To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. We mitigate price risk by efforts to balance supply and demand. None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts and gas sales contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Codification Topic 815, entitled Derivatives and Hedging.

(5) Unbilled Revenue

We bill our customers on a monthly meter reading cycle. At the end of each month, gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled.

Unbilled revenues and gas costs include the following:

(000)	December 31, 2009	June 30, 2009	December 31, 2008
Unbilled revenues ($)	6,410	1,386	9,591
Unbilled gas costs ($)	3,669	519	6,788
Unbilled volumes (Mcf)	550	55	517

Unbilled revenues are included in accounts receivable and unbilled gas costs are included in deferred gas costs on the accompanying Consolidated Balance Sheets.

(6) Defined Benefit Retirement Plan

Net periodic benefit cost for our trusteed, noncontributory defined benefit pension plan for the periods ended December 31 include the following:

	Three Months Ended December 31,		Six Months Ended December 31,		Twelve Months Ended December 31,	
($000)	2009	2008	2009	2008	2009	2008
Service cost	182	169	364	339	702	713
Interest cost	214	203	427	405	833	778
Expected return on plan assets	(238)	(253)	(476)	(505)	(982)	(999)
Amortization of unrecognized net loss	124	55	248	108	357	233
Amortization of prior service cost	(22)	(22)	(43)	(43)	(86)	(86)
Net periodic benefit cost	260	152	520	304	824	639

(7) Notes Payable

The current available bank line of credit with Branch Banking and Trust Company, is $40,000,000, of which $12,016,000, $3,653,000 and $28,653,000 were borrowed having a weighted average interest rate of 1.7%, 1.8% and 2.7% as of December 31, 2009, June 30, 2009 and December 31, 2008, respectively. Our bank line of credit extends through June 30, 2011. The interest rate on the used bank line of credit is the London Interbank Offered Rate plus 1.5%, and the annual cost of the unused bank line of credit is .125%.

Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and
- we may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented.

(8) Commitments and Contingencies

We have entered into individual employment agreements with our four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $3.1 million would be paid in addition to continuation of specified benefits for up to five years.

We are not a party to any material pending legal proceedings.

We have entered into forward purchase agreements beginning in July, 2009 and expiring at various dates through October, 2010. These agreements require us to purchase minimum amounts of natural gas throughout the term of the agreements. These agreements are established in the normal course of business to ensure adequate gas supply to meet our customers' gas requirements. The remaining aggregate minimum purchase obligations for these agreements are $411,000 and $143,000 for our fiscal years ended June 30, 2010 and 2011, respectively.

(9) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. The Kentucky Public Service Commission's regulation of our business includes setting the rates we are permitted to charge our regulated customers. The rates we currently charge our regulated customers were implemented in October, 2007. We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our natural gas and transportation services.

(10) Operating Segments

Our Company has two segments: (i) a regulated natural gas distribution, transmission and storage segment and (ii) a non-regulated segment that participates in related ventures, consisting of natural gas marketing and production. The regulated segment serves residential, commercial and industrial customers in the single geographic area of central and southeastern Kentucky. Virtually all of the revenue recorded under both segments comes from the distribution or transportation of natural gas. Price risk for the regulated segment is mitigated through our gas cost recovery clause, approved quarterly by the Kentucky Public Service Commission. Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict our demand. In addition, we are exposed to price risk resulting from changes in the market price of gas and uncommitted gas volumes of our non-regulated companies.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements which are included in our Annual Report on Form 10-K for the year ended June 30, 2009. Intersegment revenues and expenses consist of intercompany revenues and expenses from intercompany gas transportation and gas storage services. Intersegment transportation revenues and expenses are recorded at our tariff rates. Revenues and expenses for the storage of natural gas are recorded based on quantities stored. Appropriate related operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown below for the periods:

($000)	Three Months Ended December 31, 2009	Three Months Ended December 31, 2008	Six Months Ended December 31, 2009	Six Months Ended December 31, 2008	Twelve Months Ended December 31, 2009	Twelve Months Ended December 31, 2008
Operating Revenues						
Regulated						
External customers	13,807	22,177	19,072	28,826	54,724	65,354
Intersegment	866	971	1,419	1,733	3,113	3,970
Total regulated	14,673	23,148	20,491	30,559	57,837	69,324
Non-regulated						
External customers	7,307	11,781	10,173	23,240	28,092	57,667
Eliminations for intersegment	(866)	(971)	(1,419)	(1,733)	(3,113)	(3,970)
Total operating revenues	21,114	33,958	29,245	52,066	82,816	123,021
Net Income						
Regulated	1,552	870	730	411	3,798	3,360
Non-regulated	361	359	620	1,091	1,260	3,328
Total net income	1,913	1,229	1,350	1,502	5,058	6,688

(11) Gas In Storage Inventory Adjustment

We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records.

Fiscal 2009 storage field data suggested that an inventory adjustment was required related to a storage well that allowed natural gas to escape. After analyzing the data, we estimated that the adjustment amount would be in the range of $1,350,000 to $1,750,000. Based on the storage field data available at the time, we could not determine if any amount within the range was more likely than any other; therefore, we recorded a gas in storage inventory adjustment in the amount of $1,350,000. The adjustment was included in operation and maintenance expense in the Consolidated Statements of Income for the three, six and twelve months ended December 31, 2008.

Fiscal 2010 storage field data has been inconclusive as to whether any additional inventory adjustment is required. We will continue to evaluate storage field data and record inventory adjustments as required. Potential future adjustments may be in amounts within or exceeding the range determined in 2009.

On March 23, 2009, we filed an insurance claim for $1,350,000 relating to the escaped gas. On October 22, 2009, we received the preliminary findings from the external consultant engaged by the insurance company to review our claim. The preliminary findings challenge our right to recover the full amount of the claim. We disagree with the consultant's preliminary findings and have filed a rebuttal with the insurance company. We cannot predict the amount of any insurance proceeds.

Depending on the outcome of our pursuit of insurance recovery, we will also evaluate whether any unreimbursed gas losses are eligible for regulatory recovery under our gas cost recovery rate mechanism or through other recovery methods. We have not recorded any insurance recovery asset or regulatory asset in the accompanying consolidated financial statements; however, to the extent recovery becomes probable, we will evaluate recognition of an asset at that time.

(12) Share-Based Compensation

In November, 2009, at the Annual Meeting of Shareholders of Delta Natural Gas Company, Inc., our shareholders adopted and approved the Delta Natural Gas Company, Inc. Incentive Compensation Plan (the "Plan"), which was previously approved by our Board of Directors in August, 2009, subject to shareholder approval. The Plan provides for incentive compensation payable in stock, restricted stock and stock bonus awards. The Plan, which became effective on January 1, 2010, is administered by our Corporate Governance and Compensation Committee of our Board of Directors, which has complete discretion in determining our employees, officers and outside directors who shall be eligible to participate in the Plan, as well as the type, amount, terms and conditions of each award, subject to the limitations of the Plan.

The number of shares of our common stock which may be issued pursuant to the Plan may not exceed in the aggregate 500,000 shares. Shares of common stock may be available from authorized but unissued shares, shares reacquired by us or shares that we purchase in the open market. The Company must receive authorization to issue shares pursuant to the Plan from the Kentucky Public Service Commission before any shares can be awarded. In December, 2009, we submitted a filing with the Kentucky Public Service Commission seeking such authorization.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

YEAR TO DATE DECEMBER 31, 2009 OVERVIEW AND FUTURE OUTLOOK

For the six months ended December 31, 2009, consolidated net income per share of $.41 decreased $0.05 per share as compared to the $.46 net income per share for the six months ended December 31, 2008. The decrease is primarily attributable to a 41% decline in our non-regulated segment's gross margins. However, the decline is partially offset by an inventory adjustment we recorded for our gas in storage during the six months ended December 31, 2008, which is further discussed in Note 11 of the Notes to Consolidated Financial Statements.

Our regulated segment's contribution to consolidated net income for the remainder of 2010 will be dependent upon the continuing impact the weakened economic environment has on our customers. Our customers may choose to discontinue their natural gas service, be unable to pay for their natural gas service or decrease the volumes purchased from or transported by us on behalf of them.

Future profitability of the non-regulated segment is dependent on the business plans of some of our industrial and other large use customers and the market prices of natural gas, all of which are out of our control. For the six months ended December 31, 2009, we experienced a decline in the volumes sold to our non-regulated customers due to a decrease in the non-regulated customers' gas requirements. We anticipate our non-regulated segment will continue to contribute to our consolidated net income for the remainder of fiscal 2010, based on the contracts currently in place. Additionally, if natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment margins related to our natural gas production activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities.

LIQUIDITY AND CAPITAL RESOURCES

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes, gains on the sale of assets and changes in working capital.

Our ability to maintain liquidity depends on our bank line of credit, shown as notes payable on the accompanying Consolidated Balance Sheets. Notes payable increased to $12,016,000 at December 31, 2009 compared to $3,653,000 at June 30, 2009 due to gas purchased for storage and capital expenditures. Notes payable decreased to $12,016,000 at December 31, 2009 compared to $28,653,000 at December 31, 2008 due to a 63% decrease in the cost of gas purchased for storage during the current year storage injection season (April through November), as compared to the same period in the prior year.

Our liquidity is also impacted by the fact that we sometimes generate internally only a portion of the cash necessary for our capital expenditure requirements. We made capital expenditures of $2,969,000 and $7,350,000 during the six and twelve months ended December 31, 2009, respectively. In periods when cash provided by operating activities is not sufficient to meet our capital requirements, we finance the balance of our capital expenditures on an interim basis through our bank line of credit.

Long-term debt decreased to $57,259,000 at December 31, 2009, compared with $57,599,000 at June 30, 2009 and $58,063,000 at December 31, 2008. The decreases resulted from the limited redemptions made by certain holders or their beneficiaries as allowed by the Debentures and Insured Quarterly Notes.

Cash and cash equivalents were $138,000 at December 31, 2009, as compared with $123,000 at June 30, 2009 and $325,000 at December 31, 2008. The changes in cash and cash equivalents are summarized in the following table:

	Six Months Ended December 31,		Twelve Months Ended December 31,	
($000)	2009	2008	2009	2008
Provided by (used in) operating activities	(3,160)	(16,250)	28,268	4,777
Used in investing activities	(2,935)	(3,420)	(7,215)	(6,032)
Provided by (used in) financing activities	6,111	19,745	(21,240)	899
Increase (decrease) in cash and cash equivalents	16	75	(187)	(356)

For the six months ended December 31, 2009, cash used in operating activities decreased $13,090,000 (81%). Cash paid for natural gas decreased $33,326,000 due to decreases in both the cost of gas purchased and the quantities purchased. The decrease was partially offset by a $23,790,000 decrease in cash received from customers due to decreases in both sales prices and volumes sold.

For the twelve months ended December 31, 2009, cash provided by operating activities increased $23,491,000 (492%). Cash paid for natural gas decreased $56,103,000 due to decreases in both the cost of gas purchased and the quantities purchased. The decrease was partially offset by a $34,179,000 decrease in cash received from customers due to decreases in both sales prices and volumes sold.

Changes in cash used in investing activities result primarily from changes in the level of capital expenditures between years.

For the six months ended December 31, 2009, cash provided by financing activities decreased $13,634,000 (69%) due to decreased net borrowings on the bank line of credit.

For the twelve months ended December 31, 2009, cash used in financing activities increased $22,139,000 (2,463%) due to increased net repayments on the bank line of credit.

Cash Requirements

Our capital expenditures result in a continued need for capital. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities. We expect our capital expenditures for fiscal 2010 to be approximately $6.3 million.

Sufficiency of Future Cash Flows

We expect that cash provided by operations, coupled with short-term borrowings, will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that internally generated cash is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we will rely on our bank line of credit. Our current available line of credit with Branch Banking and Trust Company, shown as notes payable on the accompanying Consolidated Balance Sheets, is $40,000,000, of which $12,016,000 was borrowed at December 31, 2009. The current bank line of credit extends through June 30, 2011.

Our ability to borrow on our bank line of credit is dependent on our compliance with covenants. Our bank line of credit agreement and the Indentures relating to all of our publicly held Debentures and Insured Quarterly Notes contain defined "events of default" which, among other things, can make the obligations immediately due and payable. Of these, we consider the following covenants to be most restrictive:

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,000 (thus no retained earnings were restricted); and

- we may not assume any additional mortgage indebtedness in excess of $5,000,000 without effectively securing all Debentures and Insured Quarterly Notes equally to such additional indebtedness.

Furthermore, a default on the performance on any single obligation incurred in connection with our borrowings simultaneously creates an event of default with the bank line of credit and all of the Debentures and Insured Quarterly Notes. We were not in default on any of our bank line of credit, Debentures or Insured Quarterly Notes during any period presented. We are not aware of any events that would cause us to be in default in fiscal 2010.

Our ability to sustain acceptable earnings levels, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated sales and transportation prices we charge our customers. The Kentucky Public Service Commission sets these prices and we continuously monitor our need to file rate requests with the Kentucky Public Service Commission for general rate increase for our regulated services. The rates we currently charge our regulated customers were implemented in October, 2007.

RESULTS OF OPERATIONS

Gross Margins

Our regulated and non-regulated revenues, other than transportation, have offsetting gas expenses. Therefore, throughout the following Results of Operations, we refer to “gross margin”. With respect to our regulated and non-regulated segments, gross margin refers to operating revenues less purchased gas expense, which can be derived directly from our Consolidated Statements of Income. Operating Income as presented on the Consolidated Statements of Income is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States. “Gross margin” is a “non-GAAP financial measure”, as defined in accordance with SEC rules. We view gross margin as an important performance measure of the core profitability of our operations. The measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Natural gas prices are determined by an unregulated national market. Therefore, the price that we pay for natural gas fluctuates with national supply and demand. See Item 3 for the impact of forward contracts.

In the following table we set forth variations in our gross margins for the three, six and twelve months ended December 31, 2009 compared with the same periods in the preceding year. The variation amounts and percentages presented in the following tables for regulated and non-regulated gross margins include intersegment transactions. These intersegment revenues and expenses are eliminated in the Consolidated Statements of Income.

	2009 compared to 2008		
($000)	Three Months Ended December 31	Six Months Ended December 31	Twelve Months Ended December 31
Increase (decrease) in gross margins:			
Regulated segment			
Gas sales	(293)	(374)	(675)
On-system transportation	16	17	(335)
Off-system transportation	(154)	(370)	(644)
Other	(21)	(30)	(43)
Intersegment elimination (a)	105	314	857
Total	(347)	(443)	(840)
Non-regulated segment			
Gas sales	(611)	(1,395)	(3,780)
Other	2	(47)	(140)
Intersegment elimination (a)	(105)	(314)	(857)
Total	(714)	(1,756)	(4,777)
Decrease in consolidated gross margins	(1,061)	(2,199)	(5,617)
Percentage increase (decrease) in volumes:			
Regulated segment			
Gas sales	(11)	(9)	(6)
On-system transportation	1	(5)	(15)
Off-system transportation	(16)	(20)	(19)
Non-regulated segment			
Gas sales	(3)	(23)	(29)

(a) Intersegment eliminations represent the transportation fee charged by the regulated segment to the non-regulated segment.

Heating degree days were 104%, 103% and 100% of normal thirty year average temperatures for the three, six and twelve months ended December 31, 2009 as compared with 107%, 104% and 103% of normal temperatures in the 2008 periods. A "heating degree day" results from a day during which the average of the high and low temperature is at least one degree less than 65 degrees Fahrenheit.

For the three months ended December 31, 2009, consolidated gross margins decreased $1,061,000 (11%) due to decreased non-regulated and regulated gross margins of $714,000 (32%) and $347,000 (5%), respectively. Our non-regulated gross margins decreased due to a 29% decline in sales prices. Our regulated gross margins decreased due to a 16% decrease in off-system volumes transported due to a decline in our off-system customers' gas requirements. Additionally, we experienced an 11% decrease in regulated volumes sold due to customer conservation and warmer weather, which was partially offset by an increase in the rates billed through our weather normalization tariff.

For the six months ended December 31, 2009, consolidated gross margins decreased $2,199,000 (14%) due to decreased non-regulated and regulated gross margins of $1,756,000 (41%) and $443,000 (4%), respectively. Our non-regulated gross margins decreased due to a 23% decrease in both volumes sold and sales prices. Our regulated gross margins decreased due to a 20% decrease in off-system volumes transported due to a decline in our off-system customers' gas requirements. We primarily attribute the current economic conditions to both the declines in non-regulated volumes sold and regulated off-system volumes transported. Additionally, we experienced a 9% decrease in regulated volumes sold due to customer conservation and warmer weather which was partially offset by an increase in the rates billed through our weather normalization tariff.

For the twelve months ended December 31, 2009, consolidated gross margins decreased $5,617,000 (15%) due to decreased non-regulated and regulated gross margins of $4,777,000 (43%) and $840,000 (3%), respectively. Our non-regulated gross margins decreased due to a 29% decrease in volumes sold and a 19% decline in sales prices. The non-regulated volume sold decreased due to a decrease in our non-regulated customers' gas requirements, which we attribute primarily to current economic conditions. Our regulated gross margins decreased due to a 6% decrease in regulated gas sales due to customer conservation and warmer weather which was partially offset by an increase in the rates billed through our weather normalization tariff. Additionally, our regulated margins decreased due to a 19% decrease in off-system transportation volumes due to a decrease in our customers' gas requirements.

Operation and Maintenance

For the three months ended December 31, 2009, operation and maintenance expense decreased $1,894,000 (37%). The decrease was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 11 of the Notes to Consolidated Financial Statements) recorded in the prior year and decreased uncollectible expense ($663,000).

For the six months ended December 31, 2009, operation and maintenance expense decreased $1,552,000 (19%). The decrease was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 11 of the Notes to Consolidated Financial Statements) recorded in the prior year and decreased uncollectible expense ($743,000), partially offset by increased employee benefit expense ($208,000) and increased professional services expense ($210,000).

For the twelve months ended December 31, 2009, operation and maintenance expense decreased $2,546,000 (16%). The decrease was primarily due to an inventory adjustment for our gas in storage ($1,350,000, as further discussed in Note 11 of the Notes to Consolidated Financial Statements) recorded in the prior year and decreased uncollectible expense ($998,000).

Other Income and Deductions, Net

For the three, six and twelve months ended December 31, 2009, other income and deductions, net increased $105,000 (133%), $168,000 (193%) and $145,000 (630%), respectively. The increases were due to increases in the cash surrender value of officers' life insurance as well as increases in the fair value of the supplemental retirement plan. The increases in the fair value of the supplemental retirement plan were offset by increased operating expenses resulting from a corresponding increase in the liability of the plan.

Interest Charges

For the three, six and twelve months ended December 31, 2009, interest charges decreased $199,000 (16%), $299,000 (12%) and $412,000 (9%), respectively, due to decreased borrowings on our bank line of credit and decreases in the average interest rate on our bank line of credit.

Income Tax Expense

For the three months ended December 31, 2009, income tax expense increased $392,000 (53%). For the six and twelve months ended December 31, 2009, income tax expense decreased $137,000 (15%) and $1,138,000 (28%), respectively. These changes are a result of changes in net income before income taxes.

Basic and Diluted Earnings Per Common Share

For the three, six and twelve months ended December 31, 2009, our basic earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan.

We have no potentially dilutive securities. As a result, our basic earnings per common share and our diluted earnings per common share are the same.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We purchase our gas supply through a combination of spot market gas purchases and forward gas purchases. The price of spot market gas is based on the market price at the time of delivery. The price we pay for our natural gas supply acquired under our forward gas purchase contracts, however, is fixed prior to the delivery of the gas. Additionally, we inject some of our gas purchases into gas storage facilities in the non-heating months and withdraw this gas from storage for delivery to customers during the heating season. For our regulated business, we have minimal price risk resulting from these forward gas purchase and storage arrangements because we are permitted to pass these gas costs on to our regulated customers through the gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to price risk resulting from changes in the market price of gas on uncommitted gas volumes of our non-regulated companies.

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase contracts meet the definition of a derivative, we have designated these contracts as "normal purchases" and "normal sales" under Accounting Standards Codification Topic 815, entitled Derivates and Hedging.

We are exposed to risk resulting from changes in interest rates on our variable rate bank line of credit. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. The balances on our bank line of credit were $12,016,000, $3,653,000 and $28,653,000 on December 31, 2009, June 30, 2009 and December 31, 2008, respectively. The weighted average interest rates on our bank line of credit were 1.7%, 1.8%, and 2.7% on December 31, 2009, June 30, 2009 and December 31, 2008, respectively. Based on the amounts of our outstanding bank line of credit on December 31, 2009, June 30, 2009 and December 31, 2008, a one percent (one hundred basis point) increase in our average interest rates would result in decreases in our annual pre-tax net income of $120,000, $37,000 and $287,000, respectively. Our bank line of credit extends through June 30, 2011. The interest rate on the used bank line of credit is the London Interbank Offered Rate plus 1.5%.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures are our controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 ("Exchange Act") is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of December 31, 2009, and, based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter ended December 31, 2009 and found no changes that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings that are expected to have a materially adverse impact on our liquidity, financial condition or results of operations.

ITEM 1A. RISK FACTORS

No material changes.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) We held our Annual Meeting of Shareholders on November 19, 2009.

(b) Michael J. Kistner and Michael R. Whitley were elected to our Board of Directors for three-year terms expiring in 2012. Linda K. Breathitt, Lanny D. Greer and Billy Joe Hall will continue to serve on our Board of Directors until the election in 2010. Glenn R. Jennings, Lewis N. Melton and Arthur E. Walker, Jr. will continue to serve on our Board of Directors until the election in 2011.

(c) The total shares voted in the election of Directors were 3,029,977. There were no broker non-votes. The shares voted for each Nominee were:

Michael J. Kistner	For	2,921,041	Withheld	108,936
Michael R. Whitley	For	2,742,930	Withheld	287,047

(d) Included in our proxy materials for our 2009 Annual Meeting of Shareholders was a proposal to approve our Incentive Compensation Plan, as adopted by our Board of Directors. See Note 12 of the Notes to Consolidated Financial Statements. Our shareholders approved the incentive compensation plan, and the vote tabulation was:

For	1,162,280
Against	533,653
Abstain	75,404

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DATE: February 8, 2010

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn R. Jennings, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: February 8, 2010

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John B. Brown, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delta Natural Gas Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATE: February 8, 2010

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal
Accounting Officer)

Exhibit 32.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: February 8, 2010

/s/Glenn R. Jennings
Glenn R. Jennings
Chairman of the Board, President and Chief Executive Officer
(Duly Authorized Officer)

Exhibit 32.2

**CERTIFICATION OF THE
CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Delta Natural Gas Company, Inc. on Form 10-Q for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Delta Natural Gas Company, Inc.

DATE: February 8, 2010

/s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary
(Principal Financial Officer and Principal Accounting Officer)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934

March 4, 2010

Date of Report (Date of earliest event reported)

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	0-8788	61-0458329
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

3617 Lexington Road, Winchester, Kentucky	**40391**
(Address of principal executive offices)	(Zip Code)

859-744-6171

Registrant's telephone number, including area code

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

This Form 8-K is being filed with the Securities and Exchange Commission to provide a description of Delta Natural Gas Company, Inc.'s (the "Company," "our," "we" or "us") common stock $1.00 par value per share, in connection with a Form S-8 registering securities under the Company's Incentive Compensation Plan to be filed on or about the date hereof.

DESCRIPTION OF COMMON STOCK

Common Stock

Our articles of incorporation authorize us to issue 20,000,000 shares, $1 par value per value, of our common stock.

Holders of our common stock are entitled to receive such dividends as may be declared by our board of directors. Indentures under which our debentures and insured quarterly notes were issued include a covenant that prohibits our paying dividends on our common stock unless our consolidated shareholders' equity exceeds $25,800,000.

In the event of liquidation, holders of our common stock are entitled to share pro-rata in any distribution, after payment of all of our debts and obligations. There are no pre-emptive rights, conversion rights, redemption provisions or sinking fund provisions applicable to our common stock.

Registrar and Transfer Agent

The Registrar and Transfer Agent for our common stock is Computershare Investor Services, LLC, P. O. Box 43036, Providence, RI 02940-3036.

Voting

Each share of our common stock entitles the holder to one vote on all matters submitted to a vote of shareholders, including the election of directors. The affirmative vote of a plurality of the votes duly cast is required for the election of directors (that is, the nominees receiving the greatest number of votes will be elected). In the election of directors, cumulative voting is not permitted.

Preferred Stock

Under our articles of incorporation, we are authorized to issue up to 312,500 shares of preferred stock with a par value of $10 per share. Our board of directors, without a shareholder vote, is empowered to issue these shares in series and to set the rights pertaining to these shares, including rights to dividends, redemption, liquidation, conversion and voting. As of March 1, 2010, we have no outstanding shares of preferred stock. If we issue shares of preferred stock in the future, such preferred stock may be senior to our common stock respecting dividends and rights upon liquidation and may have other preferences and rights more favorable than our common stock.

Anti-Takeover Provisions

Our amended and restated articles of incorporation contain provisions and the Kentucky Business Corporation Act contains statutes that have anti-takeover implications. These provisions and statutes are summarized below, but are subject to numerous detailed exceptions and qualifications. For a complete understanding of these provisions and statutes, you should read our amended and restated articles of incorporation and the Kentucky Revised Statutes Section 271B.12-200 - 12-230. These provisions and statutes could also have the effect of creating impediments to extraordinary corporate transactions and frustrating persons seeking to effect a merger or otherwise gain control of us in a transaction opposed by our board of directors.

Preferred Stock. To hinder a proposed transaction opposed by our board of directors, we could issue shares of our preferred stock that might create voting impediments to extraordinary corporate transactions or frustrate persons seeking to effect a merger or otherwise gain control of us.

Classified Board. In addition to our ability to issue preferred stock, our amended and restated articles of incorporation establish a classified board of directors. Under this provision, one-third of our directors are elected each year for a three-year term. Directors may be removed without cause, but only by a vote of 80% of the shares entitled to vote at an election of our directors. Also, our amended and restated articles of incorporation provide that the number of directors as fixed by our by-laws can only be changed by an 80% or more affirmative shareholder vote or an affirmative vote of a majority of our board of directors.

Transactions with 10% Holders. Under our amended and restated articles of incorporation, the approval of some extraordinary transactions with any person or entity holding 10% or more of our voting stock may require the affirmative vote of holders of at least 80% of the outstanding shares entitled to vote, as explained below.

Under our articles of incorporation, extraordinary transactions with any person or entity holding 10% or more of our voting stock or that person's affiliate or associate that would involve a change in our control, such as mergers and other acquisition transactions, may require the approval of holders of at least 80% of each class of our outstanding voting securities.

Kentucky's Business Combination Statute. Kentucky has adopted a type of anti-takeover statue known as a business combination statute that applies to some transactions in which we might be a party and in which any interested shareholder, affiliates or associates of interested shareholders, might be a party. Under the statute, an "interested shareholder" means any person (other than us and our majority-owned subsidiaries):

- who beneficially owns 10% or more of our outstanding voting stock, or
- who is one of our affiliates and at any time during the five-year period prior to the proposed business combination owned 10% or more of our outstanding voting stock.

The business combination transactions covered by the business combination statute include, among other things, mergers, certain dispositions of assets, certain issuances and transfers of securities, certain recapitalizations and reorganizations, as well as other specified transactions involving us and an interested shareholder or its affiliates or associates.

Subject to exceptions and qualifications, the business combination statute prohibits us from engaging in a business combination with an interested shareholder or its affiliates or associates for a period of five years following the date on which the shareholder became an interested shareholder, unless a majority of our independent directors approves the business combination before the shareholder becomes an interested shareholder.

In addition, any covered business combination with an interested shareholder must be approved by either:

- the affirmative vote of at least 80% of the votes entitled to be case by outstanding shares of our voting stock; and
- the affirmative vote of at least 2/3 of the votes entitled to be cast by holders of our voting stock other than voting s6ock beneficially owned by the interested shareholder who is, or whose affiliate is, a party to the business combination or beneficially owned by an affiliate or associate of such interested shareholder; or
- a majority of our "independent directors" that are also "continuing directors".

An "independent director" is any director who is not one of our officers or full-time employees or an affiliate or associate of an interested shareholder or any of its affiliates.

A "continuing director" is:

- any director who is not an affiliate or associate of an interested shareholder and who was a director before the interested shareholder became an interested shareholder, and
- any successor to a continuing director who is not an affiliate or associate of an interested shareholder and was recommended or elected by a majority of our other continuing directors at a meeting at which a quorum consisting of a majority of our other continuing directors was present.

The foregoing vote requirements are not applicable in some instances if the consideration paid to our shareholders in the business combination transaction meets specific "fair price" determinations set forth in the Kentucky Business Corporation Act and certain other requirements regarding the payment of annual dividends and the amount of our stock acquired by the interested shareholder after it became an interested shareholder.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

DELTA NATURAL GAS COMPANY, INC.

Date: March 4, 2010

By: /s/John B. Brown
John B. Brown
Chief Financial Officer, Treasurer and Secretary

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(t)
Sponsoring Witness: Matthew Wesolosky

Description of Filing Requirement:

If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years, the utility shall file:

1. *A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each charge allocation or payment;*

2. *An explanation of how the allocator for the test period was determined; and*

3. *All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during the test period was reasonable;*

Response:

Delta had no amounts charged or allocated to it by an affiliate or general or home office, nor has Delta paid any amounts to an affiliate or general or home office.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(u)
Sponsoring Witness: W. Steven Seelye

Description of Filing Requirement:

If the utility provides gas, electric or water utility service and has annual gross revenues greater than $5,000,000, a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period.

Response:

Please refer to Volume III, the testimony of William Steven Seelye, Seelye Exhibits 5, 6, 7 and 8 for the cost of service study.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(v)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file:

1. *A jurisdictional separations study consistent with Part 36 of the Federal Communications Commission's rules and regulations; and*

2. *Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000, except local exchange access:*

   a. *Based on current and reliable data from a single time period; and*

   b. *Using generally recognized fully allocated, embedded, or incremental cost principles.*

Response:

These requirements are not applicable to Delta's Application because Delta is not a local exchange carrier.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(7)(a)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;

Response:

See the following schedules attached:

	Schedule
Balance Sheet	1
Income Statement	2

DELTA NATUR[illegible] S COMPANY, INC.

Bala[illegible] Sheet

As of Test Year December 31, 2009

FR 1[illegible] Tab 42

Schedule 1

	PSC Annual Report Balance Sheet	Adjustments		Adjustments		As Adjusted		Rate Base	Capital
Property, plant & equipment	199,165,770	(138,345)	Eliminate ARO			199,027,425		199,027,425	
Less accum prov for depr	(70,252,241)	134,408	Eliminate ARO	(1,311,714)	Depr adj	(71,429,547)		(71,429,547)	
Cash	138,146	1,556,073	1/8 working capital			1,694,219		1,694,219	
Receivables	7,884,455					7,884,455	*		
Deferred gas cost	1,573,758					1,573,758	*		
Gas in storage	3,450,410	327,491	13 month average			3,777,901		3,777,901	
Materials and supplies	525,775	70,346	13 month average			596,121		596,121	
Prepayments	1,885,545	(253,834)	13 month average			1,631,711		1,631,711	
Invest in associated companies	62,972					62,972	*		
Rec from associated companies	10,984,695					10,984,695	*		
CSV life insurance	440,746					440,746	*		
Unamortized debt expense	4,542,382					4,542,382		4,542,382	
Other	9,524,948					9,524,948	*		
Net adjustments	-	(1,696,139)		1,311,714		(384,425)	*		
	169,927,361	-		-		169,927,361			
Common equity	(58,437,147)	243,912	Eliminate subs	1,700,897	Elim unbilled	(56,492,338)			(56,492,338)
Long term debt	(57,259,000)					(57,259,000)			(57,259,000)
Notes payable	(12,015,728)					(12,015,728)			(12,015,728)
Current portion long term debt	(1,200,000)					(1,200,000)			(1,200,000)
Accounts payable	(5,165,194)					(5,165,194)	*		
Accrued taxes	2,166,119					2,166,119	*		
Refunds due customers	-					-	*		
Customers' deposits	(641,019)					(641,019)	*		
Accrued interest on debt	(854,190)					(854,190)	*		
Current deferred income taxes	(374,495)	216,839	Elim def tax not related to rate base			(157,656)		(157,656)	
Other current & accrued liabilitie[s]	(1,134,903)					(1,134,903)	*		
Deferred income taxes	(31,130,137)	1,860,584	Elim def tax not related to rate base			(29,269,553)		(29,269,553)	
Deferred investment tax credits	(129,200)					(129,200)	*		
Regulatory items	(1,344,204)					(1,344,204)	*		
Asset retirement oblig and other	(1,957,985)	1,903,380	Elim ARO and other			(54,605)		(54,605)	
Accum provision for pensions	(450,278)					(450,278)	*		
Net adjustments	-	(4,224,715)		(1,700,897)		(5,925,612)	*	-	
	(169,927,361)	-		-		(169,927,361)		110,358,398	
						* balances excluded from rate base		16,608,668	-
	-							126,967,066	(126,967,066)

DELTA NATURA ιS COMPANY, INC.
Income Statement
Test Year Ended December 31, 2009

	Regulated Income Statement (Unbilled)	Remove Unbilled Impact	Regulated Income Statement (Billed)	Adjustments		As Adjusted	Increase Required	Adjusted for Increase
Operating revenues	57,837,027	3,179,964	61,016,991	(14,944,395)	FR 10(6)(h) Tab 27 Sched 2	46,072,596	5,315,428	51,388,024
Operating expenses								
Purchased gas	29,826,554	3,118,831	32,945,385	(14,881,284)	FR 10(6)(h) Tab 27 Sched 2	18,064,101		18,064,101
O&M expenses	13,324,781		13,324,781	228,968	FR 10(6)(h) Tab 27 Sched 3	13,553,749		13,553,749
Depreciation	3,792,258		3,792,258	1,311,714	FR 10(6)(h) Tab 27 Sched 4	5,103,972		5,103,972
Other taxes	1,904,879		1,904,879	67,835	FR 10(6)(h) Tab 27 Sched 5	1,972,714		1,972,714
Income taxes	2,057,971	23,206	2,081,177	(915,653)	FR 10(6)(h) Tab 27 Sched 7	1,165,524	1,952,370	3,117,894
Total operating expenses	50,906,443	3,142,037	54,048,480	(14,188,420)		39,860,060	1,952,370	41,812,430
Operating income	6,930,584	37,927	6,968,511	(755,975)	FR 10(6)(h) Tab 27 Sched 6	6,212,536	3,363,058	9,575,594
Interest expense	4,075,601	-	4,075,601	162,017	FR 10(6)(h) Tab 27 Sched 8	4,237,618	-	4,237,618
Net income	2,854,983	37,927	2,892,910	(917,992)		1,974,918	3,363,058	5,337,976

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(7)(b)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions.

Response:

This requirement is not applicable since no pro forma adjustments for plant additions are proposed by Delta in this proceeding.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(7)(c)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(c) For each proposed pro forma adjustment reflecting plant additions provide the following information:

1. The starting date of the construction of each major component of plant;

2. The proposed in-service date;

3. The total estimated cost of construction at completion;

4. The amount contained in construction work in progress at the end of the test period;

5. A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement;

6. The original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions;

7. An explanation of any differences in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and

8. The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Response:

These requirements are not applicable since no pro forma adjustments for plant additions are proposed by Delta in this proceeding.

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(7)(d)
Sponsoring Witness: John B. Brown

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(d) The operating budget for each month of the period encompassing the pro forma adjustments.

Response:

See attached.

Delta Natural Gas Co. Inc. (Regulated Only)
Fiscal 2010 and Fiscal 2009 Income Statement Budget Detail
By Financial Statement Caption

Grouping Level 3 Description (GDSC3)	Grouping Level 4 Description (GDSC4)	Grouping Level 5 Description (GDSC5)	Grouping Level 6 Description (GDSC6)	Gl #/Description (GHCT)	Fiscal 2010 Adopted Budget	Fiscal 2009 Adopted Budget
Net (Income) Loss Before Income Taxes	Operating Revenues	Operating revenues	Residential	1.480.010 GS RATE SALES RESIDENTIAL	(33,301,400)	(30,966,000)
			Residential	1.480.050 UNMETERED GAS LIGHT REVENUE	(8,500)	(7,900)
			Residential		**(33,309,900)**	**(30,973,900)**
			Commercial	1.480.020 GS RATE SALES OTHER COMMERCIAL	(14,503,900)	(13,081,900)
			Commercial	1.480.040 GS RATE SALES SMALL COMMERCIAL	(9,926,300)	(8,949,600)
			Commercial		**(24,430,200)**	**(22,031,500)**
			Industrial	1.481.030 INTERRUPTIBLE RATE INDUSTRIAL	(444,300)	(421,400)
			Industrial		**(444,300)**	**(421,400)**
			Miscellaneous Operating Revenue	1.488.010 COLLECTION REVENUE	(194,200)	(166,200)
			Miscellaneous Operating Revenue	1.488.020 RECONNECT REVENUE	(135,500)	(120,300)
			Miscellaneous Operating Revenue	1.488.040 BAD CHECK REVENUE	(16,700)	(15,900)
			Miscellaneous Operating Revenue		**(346,400)**	**(302,400)**
			Off System Transportation Revenue	1.489.020 OFF SYSTEM TRANSP REVENUE	(2,930,100)	(2,413,500)
			Off System Transportation Revenue	1.489.021 OFF SYSTEM TRANSP REVENUE - DELGASCO	(840,600)	(1,034,300)
			Off System Transportation Revenue		**(3,770,700)**	**(3,447,800)**
			On System Transportation Revenue	1.489.040 ON SYSTEM TRANSP REVENUE	(1,639,500)	(1,533,500)
			On System Transportation Revenue	1.489.041 ON SYSTEM TRANSP DR	(2,790,300)	(2,870,900)
			On System Transportation Revenue		**(4,429,800)**	**(4,404,400)**
		Operating revenues			**(66,731,300)**	**(61,581,400)**
	Operating Revenues				**(66,731,300)**	**(61,581,400)**
	Operating Expenses	Purchased gas	Purchased Gas	1.803.000 PURCHASED GAS - OUTSIDE	37,326,300	31,559,000
			Purchased Gas		**37,326,300**	**31,559,000**
		Purchased gas			**37,326,300**	**31,559,000**
		Operations and maintenance	Labor	1.900.010 TRANS & DIST. PAYROLL	3,576,600	3,492,000
			Labor	1.903.010 CASHERING PAYROLL	444,600	440,400
			Labor	1.920.010 ADMINISTRATIVE PAYROLL	2,644,800	2,647,200
			Labor	1.926.010 TIME OFF PAYROLL	0	750,000
			Labor		**6,666,000**	**7,329,600**
			Transportation	1.900.020 OPR TRANSPORTATION EXPENSES	862,800	732,000
			Transportation	1.920.020 ADM TRANSPORTATION EXPENSES	84,000	86,400
			Transportation		**946,800**	**818,400**
			General Operations	1.821.020 CM PURIFICATION OF NATURAL GAS - MISC	130,000	120,000
			General Operations	1.871.000 TELEMETRY COSTS	76,800	72,000
			General Operations	1.880.010 OPERATIONS OFFICE TELEPHONE	98,400	108,000
			General Operations	1.880.020 OPERATIONS OFFICE UTILITIES	72,000	64,800
			General Operations	1.880.030 OPERATIONS OFFICE MISC.	108,000	103,200
			General Operations	1.880.040 FEES TRAINING SCHOOLS	38,400	43,200
			General Operations	1.880.050 UNIFORMS	43,200	43,200
			General Operations	1.880.060 WELDING SUPPLIES	18,000	18,000
			General Operations	1.881.020 RENT LAND & LAND RIGHTS	21,900	28,600
			General Operations		**606,700**	**601,000**
			Customer Billing	1.903.020 CUSTOMER COLLECTIONS & RECORDS	332,400	261,400
			Customer Billing		**332,400**	**261,400**
			Uncollectible Accounts	1.904.000 UNCOLLECTIBLE ACCOUNTS	537,300	408,000
			Uncollectible Accounts		**537,300**	**408,000**
			Administrative	1.921.010 ADM TELEPHONE	120,000	150,000

<u>Delta Natural Gas Co. Inc. (Regulated Only)</u>

Fiscal 2010 and Fiscal 2009 Income Statement Budget Detail

By Financial Statement Caption

Grouping Level 3 Description (GDSC3)	Grouping Level 4 Description (GDSC4)	Grouping Level 5 Description (GDSC5)	Grouping Level 6 Description (GDSC6)	Gl #/Description (GHCT)	Fiscal 2010 Adopted Budget	Fiscal 2009 Adopted Budget
Net (Income) Loss Before Income Taxes	Operating Expenses	Operations and maintenance	Administrative	1.921.030 BOOKS & SUBSCRIPTIONS	27,000	21,600
			Administrative	1.921.040 COMPANY FORMS	24,000	19,200
			Administrative	1.921.050 SMALL SUPPLY ITEMS	60,000	66,000
			Administrative	1.921.060 MISCELLANEOUS OTHER ITEMS	192,000	168,000
			Administrative	1.921.070 EMPLOYEE MEMBERSHIPS	5,000	5,400
			Administrative	1.921.080 SAFETY LITERATURE & EDUCATION	24,000	30,000
			Administrative	1.921.090 ENGR & DRAFTING SUPPLIES	7,200	6,000
			Administrative	1.921.100 ADM UTILITIES	57,600	50,400
			Administrative	1.921.210 TRAVEL ETC CO BUS PRES & CEO	6,000	8,000
			Administrative	1.921.220 TRAVEL ETC CO BUS OFFICERS	12,000	12,000
			Administrative	1.921.230 TRAVEL ETC CO BUS OPER & CONST	8,400	12,000
			Administrative	1.921.240 TRAVEL ETC CO BUS ADM&CUST SER	9,600	7,200
			Administrative	1.921.260 TRAVEL ETC CO BUS FINANCE	18,000	22,900
			Administrative	1.921.290 CO. BUS. MEALS & ENTERTAINMENT	37,200	36,000
			Administrative	1.921.300 COMPUTER EQUIPMENT OPERATIONS	10,800	13,200
			Administrative		**618,800**	**627,900**
			Outside Services	1.923.010 OUTSIDE SERVICES LEGAL	70,000	70,000
			Outside Services	1.923.020 OUTSIDE SERVICES ACCOUNTING	306,000	282,500
			Outside Services	1.923.030 OUTSIDE SERVICES JANITORIAL	64,800	66,000
			Outside Services	1.923.040 OUTSIDE SERVICES OTHER	56,100	61,300
			Outside Services	1.923.050 OUTSIDE SERVICES COMPUTERS	360,300	368,800
			Outside Services		**857,200**	**848,600**
			Insurance	1.924.000 INSURANCE	858,000	766,800
			Insurance		**858,000**	**766,800**
			Employee Benefits	1.926.020 PENSION	1,589,900	697,200
			Employee Benefits	1.926.030 EMPLOYEE 401K PLAN	300,000	290,400
			Employee Benefits	1.926.040 MEDICAL COVERAGE	1,500,000	1,500,000
			Employee Benefits	1.926.050 SALARY CONTINUATION COVERAGE	139,200	135,600
			Employee Benefits	1.926.070 EMPLOYEE EDUCATION	14,400	16,800
			Employee Benefits	1.926.080 EMPLOYEE RECREATION & SOCIAL	11,000	9,000
			Employee Benefits	1.926.100 SUPPLEMENTAL RETIREMENT PLAN	60,000	60,000
			Employee Benefits		**3,614,500**	**2,709,000**
			General Administration	1.908.010 CUSTOMER ASSISTANCE	30,000	30,000
			General Administration	1.913.000 ADVERTISING	9,000	9,600
			General Administration	1.928.000 REGULATORY COMMISSION EXPENSE	187,100	171,900
			General Administration	1.930.010 DIRECTOR FEES & EXPENSES	204,000	182,400
			General Administration	1.930.020 COMPANY MEMBERSHIPS	64,000	65,000
			General Administration	1.930.030 FEES CONVENTIONS & MEETINGS	8,400	8,500
			General Administration	1.930.040 MARKETING	13,200	13,200
			General Administration	1.930.050 COMPANY RELATIONS	21,600	20,000
			General Administration	1.930.060 TRUSTEE, REGISTRAR, AGENT FEES	72,000	72,000
			General Administration	1.930.080 STOCKHOLDER REPORTS	95,600	84,900
			General Administration	1.930.090 CUSTOMER & PUBLIC INFORMATION	37,000	38,000
			General Administration	1.930.100 PUBLIC & COMMUNITY RELATIONS	25,000	25,000
			General Administration	1.930.110 CONSERVATION PROGRAM	6,000	40,000
			General Administration	1.930.120 LOBBYING EXPENDITURES	20,000	15,000

Delta Natural Gas Co. Inc. (Regulated Only)
Fiscal 2010 and Fiscal 2009 Income Statement Budget Detail
By Financial Statement Caption

Grouping Level 3 Description (GDSC3)	Grouping Level 4 Description (GDSC4)	Grouping Level 5 Description (GDSC5)	Grouping Level 6 Description (GDSC6)	Gl #/Description (GHCT)	Fiscal 2010 Adopted Budget	Fiscal 2009 Adopted Budget
Net (Income) Loss Before Income Taxes	Operating Expenses	Operations and maintenance	General Administration		**792,900**	**775,500**
			Expenses Transferred	1.922.000 EXP. TRANSFERRED - CAPITAL	(2,742,800)	(2,735,700)
			Expenses Transferred	1.922.100 EXP. TRANSFERRED I/C	(244,000)	(202,000)
			Expenses Transferred		**(2,986,800)**	**(2,937,700)**
			Other	1.753.020 WELLS & GATHERING MISC	1,200	1,200
			Other	1.754.020 COMPRESSOR STATION MISC.	156,000	120,000
			Other	1.765.020 MNT COMPRESSOR STATION OTHER	48,000	36,000
			Other	1.816.020 CM WELLS EXPENSES - MISC	6,000	3,600
			Other	1.818.020 CM COMPRESSOR STATION EXPENSES - MISC	36,000	28,800
			Other	1.824.020 CM OTHER UNDERGROUND STORAGE EXPENSES - MISC	6,000	3,000
			Other	1.825.000 CM STORAGE WELL ROYALTIES/RENTS	59,000	59,500
			Other	1.831.020 CM MAINTENANCE STRUCTURES & IMPROVEMENTS - MISC	9,000	8,000
			Other	1.832.020 CM MAINTENANCE OF RESERVOIRS AND WELLS - MISC	52,500	52,500
			Other	1.833.020 CM MAINTENANCE OF LINES - MISC	1,000	1,000
			Other	1.834.020 CM MAINTENANCE OF COMPRESSOR STAT EQUIP - MISC	21,000	18,000
			Other	1.835.020 CM MAINTENANCE OF MEAS & REG STAT EQUIP - MISC	1,000	1,000
			Other	1.837.020 CM MAINTENANCE OF OTHER EQUIPMENT - MISC	6,000	6,000
			Other	1.856.000 RIGHT OF WAY CLEARING	130,000	130,000
			Other	1.889.000 MNT REG STATION TRANS & DIST.	7,000	6,000
			Other	1.894.020 MNT OF OTHER EQUIPMENT OTHER	102,000	96,000
			Other	1.900.030 SMALL TOOLS & WORK EQUIPMENT	125,000	120,000
			Other	1.932.010 MNT COMMUNICATION EQUIPMENT	45,600	42,000
			Other	1.932.020 MNT OFFICE EQUIPMENT	30,000	34,800
			Other	1.932.030 MNT GENERAL STRUCTURES	60,000	60,000
			Other	1.932.050 MAINTENANCE COMPUTER EQUIPMENT	135,100	197,200
			Other		**1,037,400**	**1,024,600**
			Mains	1.887.020 MNT TRANS & DIST MAINS OTHER	72,000	210,000
			Mains		**72,000**	**210,000**
			Meter & Regulators	1.893.020 MNT OF METERS & REG OTHER	48,000	48,000
			Meter & Regulators		**48,000**	**48,000**
		Operations and maintenance			**14,001,200**	**13,491,100**
		Depreciation and depletion	Depreciation Expense	1.403.000 DEPRECIATION EXPENSE	3,850,800	3,745,000
			Depreciation Expense	1.406.000 AMORT OF GAS PLANT ACQ ADJ-TRANEX	(58,800)	(58,800)
			Depreciation Expense	1.406.010 AMORT OF GAS PLANT ACQ ADJ-MT OLIVET	46,800	46,800
			Depreciation Expense		**3,838,800**	**3,733,000**
		Depreciation and depletion			**3,838,800**	**3,733,000**
		Taxes other than income taxes	Property Taxes	1.408.010 LICENSE & PRIVILEGE FEES	6,000	7,000
			Property Taxes	1.408.020 PROPERTY TAXES	1,253,400	1,305,600
			Property Taxes		**1,259,400**	**1,312,600**
			Payroll Taxes	1.408.030 PAYROLL TAXES	587,700	574,200
			Payroll Taxes		**587,700**	**574,200**

Delta Natural Gas Co. Inc. (Regulated Only)
Fiscal 2010 and Fiscal 2009 Income Statement Budget Detail
By Financial Statement Caption

Grouping Level 3 Description (GDSC3)	Grouping Level 4 Description (GDSC4)	Grouping Level 5 Description (GDSC5)	Grouping Level 6 Description (GDSC6)	Gl #/Description (GHCT)	Fiscal 2010 Adopted Budget	Fiscal 2009 Adopted Budget
Net (Income) Loss Before Income Taxes	Operating Expenses	Taxes other than income taxes			**1,847,100**	**1,886,800**
	Operating Expenses				**57,013,400**	**50,669,900**
	Interest Charges	Interest charges	Interest On Long Term Debt	1.427.000 INTEREST ON LONG TERM DEBT	3,638,400	3,676,800
			Interest On Long Term Debt		**3,638,400**	**3,676,800**
			Interest On Short Term Debt	1.431.020 INTEREST ON SHORT-TERM DEBT	560,000	749,000
			Interest On Short Term Debt	1.431.021 SUBSIDIARY INTEREST	(215,200)	(243,700)
			Interest On Short Term Debt		**344,800**	**505,300**
			Other Interest	1.431.010 INTEREST ON CUSTOMER DEPOSITS	37,200	37,200
			Other Interest		**37,200**	**37,200**
			Amortization Of Debt Expense	1.428.000 AMORT OF DEBT EXPENSES	387,600	387,200
			Amortization Of Debt Expense		**387,600**	**387,200**
		Interest charges			**4,408,000**	**4,606,500**
	Interest Charges				**4,408,000**	**4,606,500**
	Income Taxes	Income taxes	Current Federal	1.409.070 ESTIMATED INTERIM INCOME TAXES	2,015,700	2,393,300
			Current Federal		**2,015,700**	**2,393,300**
		Income taxes			**2,015,700**	**2,393,300**
	Income Taxes				**2,015,700**	**2,393,300**
Net (Income) Loss Before Income Taxes					**(3,294,200)**	**(3,911,700)**
Summary					**(3,294,200)**	**(3,911,700)**

Delta Natural Gas Company, Inc.
Case No. 2010-00116
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(7)(e)
Sponsoring Witness: W. Steven Seelye

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.

Response:

Please refer to Volume III, the testimony of William Steven Seelye, Seelye Exhibit 10. No changes are proposed by Delta to the test period-end level of customers and thus there is no related revenue requirement impact.