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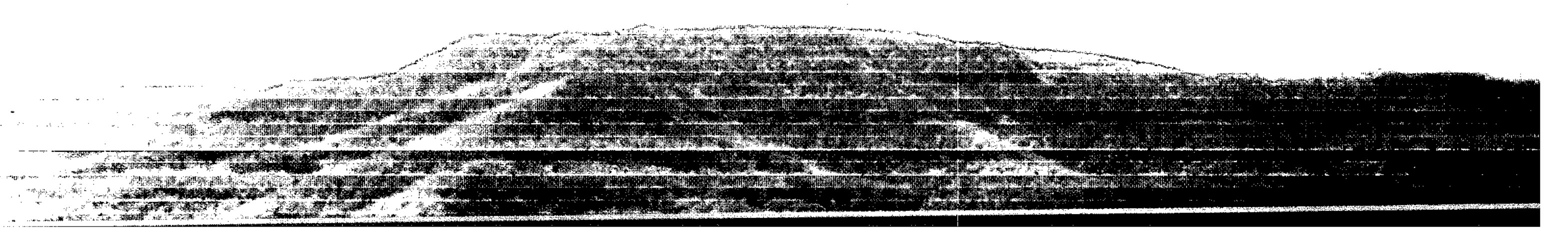
P.E. 6/30/03

2003 ANNUAL REPORT

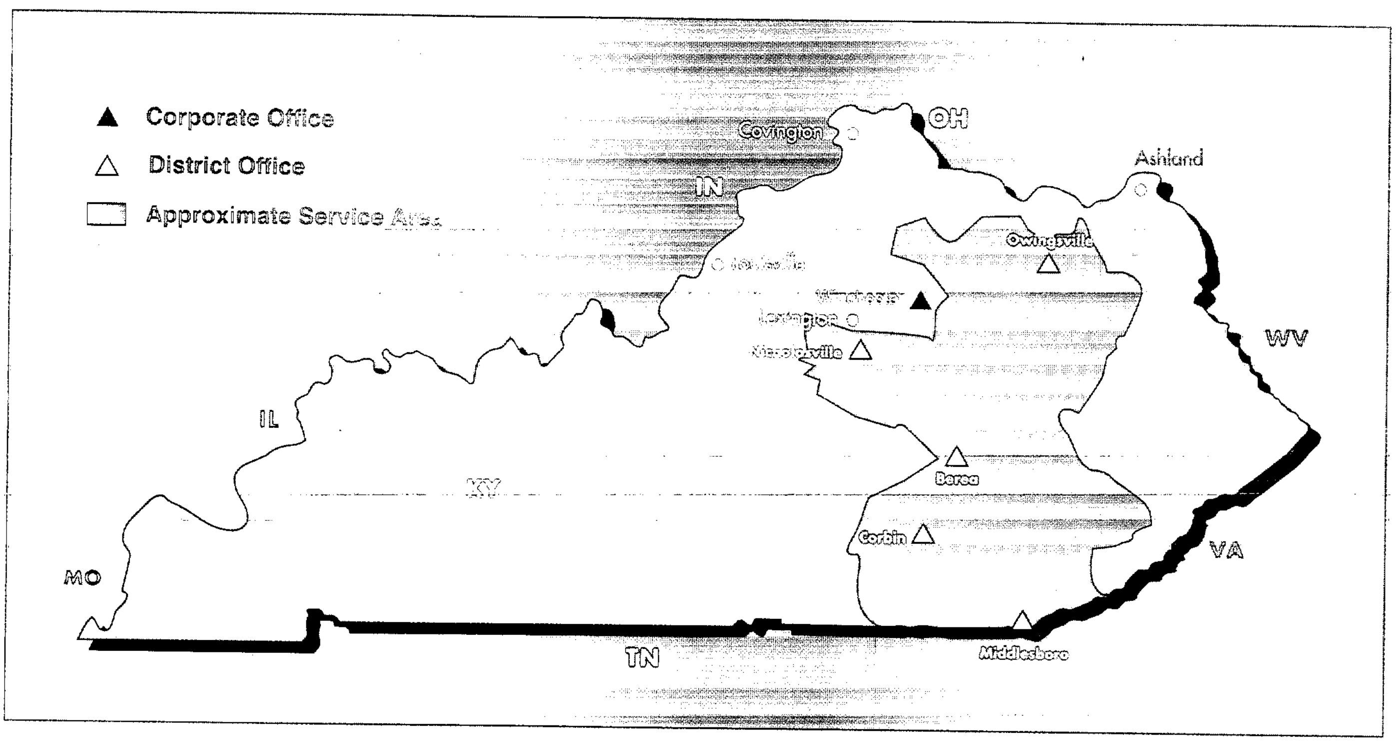
DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES



MISSION STATEMENT

Delta will be a premier provider of natural gas services while having a significant positive impact on its customers, employees and shareholders.

SERVICE AREA



Delta had another successful year in 2003, with earnings of $1.46 per common share. The weather in fiscal 2003 was colder than normal, with heating degree days that were 6% colder than thirty-year average ("normal") temperatures. Our weather normalization tariff reduced rates billed to customers this past winter to reflect the colder weather.

Our subsidiaries performed well this past year and continued their contribution to consolidated net income. Our transportation revenues continued to increase as we had a record throughput of almost 15 billion cubic feet for 2003. Also, interest rates stayed low and that helped as well with reduced short-term interest expense. During 2003 we completed efforts to strengthen our balance sheet. This included a $20 million long-term debt issuance in February, followed by a successful offering of 600,000 common shares in May. We paid off our 8.3% debentures and paid down our short-term borrowings. These financing activities have strengthened our balance sheet and, coupled with our $40 million unsecured line of credit, have put us in good position for the future.

Delta's stock has performed well this past year. Our annualized dividend of $1.18 is a cash yield of 5% on our recent stock prices. It was positive to see the stock price increase after the recent equity offering.

We are injecting gas into our Canada Mountain underground storage field for withdrawal this coming winter. In fiscal 2003 we used this storage capacity to help meet our peak day and seasonal needs as well as to keep our rates to our customers as low as possible. We anticipate the same benefits for 2004. This should help us to mitigate the impacts of a volatile national market for natural gas supplies over the coming year.

We welcomed Michael J. Kistner to Delta's Board of Directors in December, 2002. We are very pleased that Mike agreed to serve the Company in this fashion. His wealth of business experience is a tremendous addition and complements well our already strong, diverse Board.

We appreciate the hard work and dedication of Delta's employees. We extend our sincere thanks to, and appreciation for, all of them. We are especially thankful for the efforts and dedication of Delta's officer team. Their broad and varied experiences bring much to Delta and each makes a significant contribution to the overall effort to provide leadership to the Company.

We also truly appreciate your support of the Company, and we welcome all of our new common stockholders from our recent offering. Your Board of Directors met on August 18, 2003 and declared the quarterly dividend of $.295 to be paid September 15 to shareholders of record on August 31.

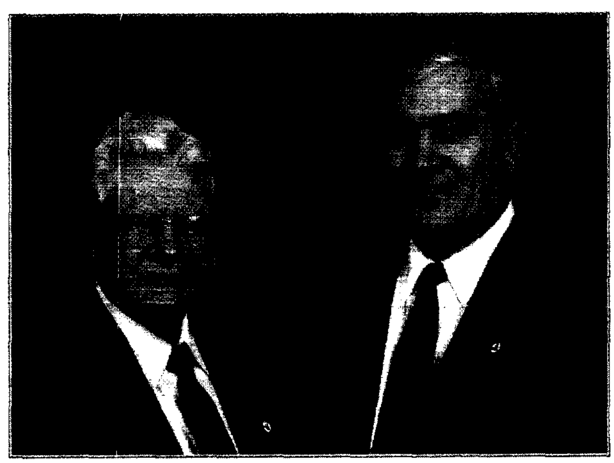
Please let us know of any concerns you may have or if we can be of assistance to you in any way.

Sincerely,

Harrison D. Peet
Chairman of the Board

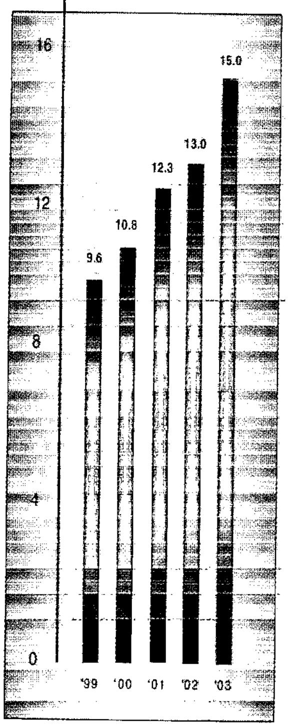
Glenn R. Jennings
President and
Chief Executive Officer

August 19, 2003

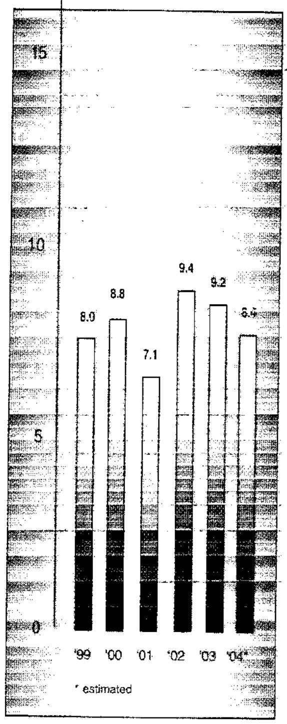


Peet *Jennings*

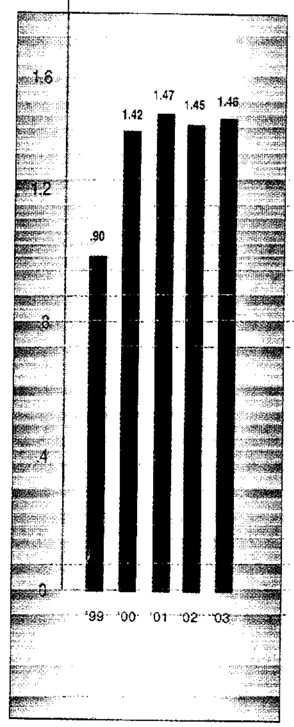
System Throughput
(Billion Cu. Ft.)



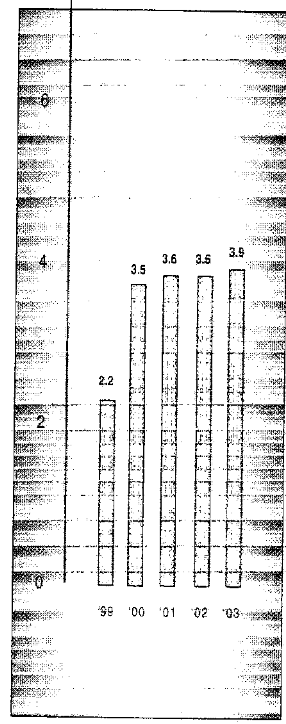
Capital Expenditures
($ Millions)



Earnings Per Common Share
($)



Net Income
($ Millions)



UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended June 30, 2003.

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 number 0-8788.

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

Kentucky	**61-0458329**
(State of Incorporation)	*(IRS Employer Identification Number)*
3617 Lexington Road **Winchester, KY 40391**	**40391**
(Address of principal executive offices)	*(Zip Code)*

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

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

Title of Each Class	Name on Each Exchange on Which Registered
None	None

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

Common Stock $1 Par Value

(Title of class)

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 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 an accelerated filer (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. $54,828,232

As of August 29, 2003, Delta Natural Gas Company, Inc. had outstanding 3,174,628 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, 2003, is incorporated by reference in Part III of this Report.

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PART I

Item 1. Business

General

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 and oil 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 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 to entail 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 an unregulated segment. See Note 13 of the Notes to Consolidated Financial Statements. Through our regulated segment, we sell natural gas to our retail customers in 23 predominantly rural communities. 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 weather normalization provision which has reduced fluctuations in our earnings due to variations in weather and gas prices and a gas cost recovery clause.

We operate our unregulated segment through three wholly-owned subsidiaries. Two of these subsidiaries, Delta Resources, Inc. and Delgasco, Inc., purchase natural gas on the national market and from Kentucky producers. We resell this gas to industrial customers on our distribution system and to others not on our system. Our third subsidiary that is part of the unregulated segment, Enpro, Inc., produces a relatively small amount of natural gas and oil that is sold on the unregulated 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 7,000 customers, and in Berea we serve approximately 4,000 customers.

The communities we serve continue to expand, resulting in growth opportunities for us. Industrial parks have been built in our service areas, resulting in some new industrial customers.

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 rules of the Kentucky Public Service Commission permit 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 retail 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. Kentucky Public Service Commission regulations, however, provide for 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 retail customers. These alternate sources include electricity, coal, oil, propane and wood. Our unregulated 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 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 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 function. 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.

Gas Supply

We purchase our natural gas from a combination of interstate and Kentucky sources. In our fiscal year ended June 30, 2003, 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 for our Columbia Gas Transmission, Columbia Gulf Transmission supplied areas and Tennessee Gas Pipeline supplied areas with Woodward Marketing, L.L.C. Under these commodity requirements agreements, the gas marketer 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 agreement with Woodward for the Tennessee Gas Pipeline supplied service areas is for a term that expires on April 30, 2004. Our agreement with Woodward, under which we purchase the natural gas transported for us by Columbia Gas Transmission Corporation and Columbia Gulf Transmission Corporation, became effective May 1, 2003 and replaced the supply agreement with Dynegy Marketing and Trade which expired April 30, 2003. The term for the Woodward Columbia Gas Transmission contract extends through April 30, 2006. In our fiscal year ended June 30, 2003, approximately 30% of Delta's gas supply was purchased under our agreements with Woodward. We purchased approximately 16% of Delta's gas supply from Dynegy prior to the expiration of that agreement.

We also purchase additional interstate natural gas from Woodward, as needed, outside of our commodity requirements agreements with Woodward. This spot gas purchasing arrangement is pursuant to an agreement with Woodward that expires on March 31, 2005. Delta's purchases from Woodward 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 Woodward, with an agreed-to fixed price adjustment per Million British Thermal Units purchased.

Delta purchases gas from M & B Gas Services, Inc. for injection into our underground natural gas storage field and to supply our southern system. We are not obligated 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, 2003, approximately 53% 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 production and storage fields by Tennessee Gas Pipeline Company, Columbia Gas Transmission Corporation, Columbia Gulf Transmission Corporation and Texas Eastern Transmission Corporation.

Our agreements with Tennessee Gas Pipeline extend by their terms until 2005 and, unless terminated by one of the parties, automatically renew for subsequent five-year terms. However, Tennessee has represented to us that as a result of Tennessee's Early Renewal Incentive Option Program begun in 1999, our agreements with Tennessee extend through 2008 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 Million cubic feet ("Mcf") per day for us. During fiscal 2003, Tennessee transported a total of 1,354,000 Mcf for us under these contracts. Annually, approximately 29% of Delta's supply requirements flow through Tennessee Gas Pipeline 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 production area storage fields and its market area 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 12,500 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 2003 Columbia Gas and Columbia Gulf transported for us a total of 788,000 Mcf, or approximately 17% of Delta's supply requirements, under all of our agreements with them.

All of our transport agreements with Columbia Gas and Columbia Gulf extend through 2008 and thereafter 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 below. The amounts transported under the agreement between Columbia Gulf and this gas marketer for fiscal 2003 constituted approximately 53% 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 Transmission Corporation. However, Woodward has an arrangement with Texas Eastern to transport the gas to us that we purchase from that marketer. Consequently, Texas Eastern transports a small percentage of our interstate gas supply. In our fiscal year ended June 30, 2003, Texas Eastern transported approximately 11,000 Mcf of natural gas to our system, which constituted less than 1% of our gas supply.

Kentucky Gas Supply

We have an agreement with Columbia Natural Resources to purchase natural gas through October 31, 2004, and thereafter it will renew for additional terms of one year each until terminated by one of the parties. We purchased 60,000 Mcf from Columbia Natural Resources during fiscal 2003. The price for the gas we purchase from Columbia Natural Resources 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, with a fixed adjustment per million British Thermal units of gas purchased. Columbia Natural Resources 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. The storage gas is delivered during the summer injection season by Columbia Gulf on behalf of M & B to an interconnection point between Columbia Gulf and us where we purchase and receive the gas and flow it to our storage field. M & B arranges transportation of the gas through the Columbia Gulf system to us. 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. During fiscal 2003, we withdrew 1,793,000 Mcf from this storage field.

Delta purchased a small percentage of its gas supply from Enpro through December 31, 2001.

We continue to seek additional gas supplies from available sources. We will 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 retail natural gas distribution and our transportation services. The Kentucky Public Service Commission regulation of our business includes setting the rates we are permitted to charge our retail customers and our transportation customers.

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our retail gas and transportation services. Through these general rate cases, we are able to adjust the sales prices of our retail gas we sell to and transport for our customers.

On December 27, 1999, the Kentucky Public Service Commission approved an annual revenue increase for us of $420,000. We filed this general rate case in July 1999, and it is our most recent filing of a rate case. The approval of our requests in this rate case included a weather normalization provision that permits us to adjust rates for the billing months of December through April to reflect variations from 30-year average winter temperatures.

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 recovery clause, we are required to make quarterly filings with the Kentucky Public Service Commission.

During July, 2001, the Kentucky Public Service Commission required an independent audit of our gas procurement activities and the gas procurement activities of four other gas distribution companies as part of its investigation of increases in wholesale natural gas prices and their impact on customers. The Kentucky Public Service Commission indicated that Kentucky distributors had generally developed sound planning and procurement procedures for meeting their customers' natural gas requirements and that these procedures had provided customers with reliable supplies of natural gas at reasonable costs. The Kentucky Public Service Commission noted the events of the prior year, including changes in natural gas wholesale markets. It required the auditors to evaluate distributors' gas planning and procurement strategies in light of the recent more volatile wholesale markets, with a primary focus on a balanced portfolio of gas supply that balances cost issues, price risk and reliability. The auditors were selected by the Kentucky Public Service Commission. The final audit report, dated November 15, 2002, contains 16 procedural and reporting-related recommendations in the areas of gas supply planning, organization, staffing, controls, gas supply management, gas transportation, gas balancing, response to regulatory change and affiliate relations. The report also addresses several general areas for the five gas distribution companies involved in the audit, including Kentucky natural gas price issues, hedging, gas cost recovery mechanisms, budget billing, uncollectible accounts and forecasting. In January, 2003, we responded to the auditors with our comments on action plans they drafted relating to the recommendations. Our first status report on the action plans for the 16 recommendations is due to be filed by us with the Kentucky Public Service Commission by September 30, 2003. We believe that implementation of the recommendations will not result in a significant impact on our financial position or results of operations.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities and communities 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 a local franchise. We hold franchises in four of the cities and seven of the communities we serve. In the other cities and communities we serve, either our franchises have expired, the communities do not have governmental organizations authorized to grant franchises, or the local governments have not required or do not want to offer a franchise. We attempt to acquire or reacquire franchises whenever feasible.

Without a franchise, a local government 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 or community. To date, the absence of a franchise has caused no adverse effect on our operations.

Capital Expenditures

Capital expenditures during 2003 were $9.2 million and for 2004 are estimated to be $8.4 million. Our planned 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 line of credit. The current available line of credit is $40 million, of which $1 million had been borrowed at June 30, 2003.

During February, 2003, we completed the sale of the aggregate principal amount of $20,000,000 of 7.00% Debentures due 2023. We used the net proceeds to redeem our 8.30% Debentures outstanding in the aggregate principal amount of $14,806,000 and to pay down our short-term notes payable.

During May, 2003, we issued and sold through underwriters, 600,000 shares of our common stock. The net proceeds of $12,493,000 from the sale of the stock were used to pay down our short-term notes payable.

Present plans are to utilize the short-term 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.

During 2003 the requirements of the Employee Stock Purchase Plan (see Note 4(c) of the Notes to Consolidated Financial Statements) were met through the issuance of 4,728 shares of common stock resulting in an increase of $103,000 in Delta's common shareholders' equity. The Dividend Reinvestment and Stock Purchase Plan (see Note 5 of the Notes to Consolidated Financial Statements) resulted in the issuance of 30,821 shares of common stock providing an increase of $676,000 in Delta's common shareholders' equity. Our expenses under the stock plan were $53,000, $52,000 and $49,000 for the three years ended June 30, 2003, 2002 and 2001, respectively.

Employees

On June 30, 2003, we had 156 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 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.

Consolidated Statistics

For the Years Ended June 30,	**2003**	2002	2001	2000	1999
Average Retail Customers Served					
Residential	**33,757**	33,624	33,691	33,251	32,429
Commercial	**5,290**	5,235	5,227	5,110	4,958
Industrial	**63**	62	65	66	68
Total	**39,110**	38,921	38,983	38,427	37,455
Operating Revenues ($000)					
Residential sales	**26,749**	23,203	28,088	19,672	17,329
Commercial sales	**16,916**	13,832	17,040	10,952	10,039
Industrial sales	**1,607**	1,141	2,046	1,104	1,173
Total regulated sales	**45,272**	38,176	47,174	31,728	28,541
On-system transportation	**3,873**	3,826	3,895	4,056	4,107
Off-system transportation	**1,560**	1,220	814	522	363
Non-regulated sales	**20,611**	17,191	49,492	18,103	14,232
Other	**195**	198	248	190	170
Eliminations for intersegment	**(3,131)**	(4,741)	(30,853)	(8,672)	(8,741)
Total	**68,380**	55,870	70,770	45,927	38,672
System Throughput (Million Cu. Ft.)					
Residential sales	**2,416**	2,133	2,614	2,266	2,223
Commercial sales	**1,627**	1,389	1,666	1,397	1,401
Industrial sales	**181**	142	249	174	189
Total regulated sales	**4,224**	3,664	4,529	3,837	3,813
On-system transportation	**5,299**	4,865	4,769	4,704	4,434
Off-system transportation	**5,396**	4,215	2,793	1,767	1,280
Non-regulated sales	**3,560**	3,858	4,851	4,939	4,351
Eliminations for intersegment	**(3,523)**	(3,641)	(4,666)	(4,415)	(4,310)
Total	**14,956**	12,961	12,276	10,832	9,568
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	72	63	78	68	69
Lexington, Kentucky Degree Days					
Actual	**4,914**	4,137	4,961	4,162	4,188
Percent of 30 year average (4,643)	**105.8**	89.1	106.8	89.6	90.2

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 2,400 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 13 of the Notes to Consolidated Financial Statements for a description of Delta's two business segments.

Through our wholly-owned subsidiary, Enpro, we produce oil and gas as part of the unregulated segment of our business.

Enpro owns interests in oil and gas leases on 11,000 acres located in Bell, Knox and Whitley Counties. Forty gas wells and five oil wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 3 million Mcf. Oil production from the property has not been significant. Also, Enpro owns the oil and gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties are currently non-producing, and we have performed no reserve studies on these properties. Enpro produced a total of 177,000 Mcf of natural gas during fiscal 2003 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 financial condition or our results of operations.

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

No matter was submitted during the fourth quarter of 2003.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

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 Debentures.

Our common stock is traded on the Nasdaq National Market System and trades under the symbol "DGAS". There were 2,714 record holders of our common stock as of June 30, 2003. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the Nasdaq National Market System and the cash dividends declared per share.

	Range of Stock Prices($)		Dividends
Quarter	High	Low	Per Share($)
Fiscal 2003			
First	21.97	18.50	.295
Second	21.99	19.50	.295
Third	23.99	21.24	.295
Fourth	24.10	21.00	.295
Fiscal 2002			
First	20.43	18.90	.29
Second	20.99	18.67	.29
Third	23.08	19.75	.29
Fourth	22.50	21.47	.29

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

In July, 2001, we distributed 4,916 shares of our common stock to our employees under our Employee Stock Purchase Plan (see Note 4c of the Notes to Consolidated Financial Statements). We received cash consideration of $19.58 per share for one half of those shares (2,458 shares), for a total cash consideration of $48,000, while one-half of the shares (2,458 shares) were provided to our employees without cash consideration as a part of our compensation and benefits for our employees. We have continued our Employee Stock Purchase Plan, and in July, 2002 and 2003 we distributed, respectively, 4,728 and 4,504 shares of our common stock to our employees under similar terms and received, respectively, a total of $52,000 and $53,000 in cash consideration from our employees.

Our Board of Directors authorized the continuation of our Employee Stock Purchase Plan for fiscal 2004 under similar terms, and we anticipate no material changes in the level of contributions to the plan from our employees or from Delta.

We offer and sell our securities through our Employee Stock Purchase Plan pursuant to the exemption from registration provided by Rule 147 under the Securities Act of 1933. This exemption is available since we are incorporated and doing business in Kentucky and all our eligible employees are residents of Kentucky. Our Employee Stock Purchase Plan was authorized by our Board of Directors, but was not required to be submitted to our shareholders for approval.

Also, in June of 2001, 2002 and 2003, we awarded, respectively, a total of 900, 800 and 900 shares of our common stock to our directors (100 shares per director per year). We received no cash consideration for the shares, which were provided to our directors as a part of their compensation. This transaction may not have involved a "sale" of securities under the Securities Act of 1933, and in any event, the securities were qualified for an exemption from registration provided by Rule 147 under the Securities Act of 1933. This exemption is available since we are incorporated and doing business in Kentucky and all participating directors are residents of Kentucky.

No underwriters were engaged in connection with any of the foregoing transactions, and thus no underwriter discounts or commissions were paid in connection with any of the foregoing.

Item 6. Selected Financial Data

For the Years Ended June 30,	**2003**	2002	2001	2000	1999
Summary of Operations ($)					
Operating revenues	**68,380,263**	55,870,219	70,770,156	45,926,775	38,672,238
Operating income	**8,526,366**	8,401,452	8,721,719	8,176,722	6,652,070
Net income	**3,850,607**	3,636,713	3,635,895	3,464,857	2,150,794
Basic and diluted earnings per common share	**1.46**	1.45	1.47	1.42	.90
Dividends declared per common share	**1.18**	1.16	1.14	1.14	1.14
Average Number of Common Shares Outstanding (basic and diluted)	**2,641,829**	2,513,804	2,477,983	2,433,397	2,394,181
Total Assets ($)	**132,573,789**	126,487,085	124,179,138	112,918,919	107,473,117
Short-Term Debt ($)(1)	**2,681,099**	21,105,000	19,250,000	11,375,000	8,145,000
Capitalization ($)					
Common shareholders' equity	**45,892,597**	34,182,277	32,754,560	31,297,418	29,912,007
Long-term debt (2)	**53,373,000**	48,600,000	49,258,902	50,723,795	51,699,700
Total capitalization	**99,265,597**	82,782,277	82,013,462	82,021,213	81,611,707
Other Items ($)					
Capital expenditures	**9,195,099**	9,421,765	7,069,713	8,795,653	7,982,143
Total plant, before accumulated depreciation	**163,745,044**	156,305,063	147,792,390	141,986,856	133,804,954

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

(2) During February, 2003, we issued $20,000,000 aggregate principal amount of 7.00% Debentures due 2023. The net proceeds of the offering were $19,181,000. We used the net proceeds to redeem $14,806,000 aggregate principal amount of our 8.30% Debentures due 2026 and to pay down our short-term notes payable. During May, 2003, we used the net proceeds of $12,493,000 from our sale of 600,000 shares of common stock to pay down our short-term notes payable.

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

Overview

The Kentucky Public Service Commission regulates our utility operations. As a part of this regulation, the Kentucky Public Service Commission sets the rates we are permitted to charge our customers. These rates have a significant impact on our annual revenues and profits. See "Business – Regulatory Matters".

The rates approved by the Kentucky Public Service Commission allow us a specified rate of return on our regulated investment. The rates we are allowed to charge our customers also permit us to pass through to our customers changes in the cost of our gas supply. See "Business – Regulatory Matters".

Our regulated business is temperature-sensitive. Our regulated sales volumes in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. We anticipate that this sensitivity to seasonal and other weather conditions will continue to be reflected in our sales volumes in future periods. The impact of unusual winter temperatures on our revenues was ameliorated to some extent when the Kentucky Public Service Commission permitted us to start adjusting our winter rates in response to unusual winter temperatures in the year 2000. Under the weather normalization tariff, we are permitted to increase our rates for residential and small non-residential customers when, based on a 30-year average temperatures, winter weather is warmer than normal, and we are required to decrease our rates when winter weather is colder than normal. We are permitted to adjust these rates for the billing months of December through April.

Liquidity and Capital Resources

Because of the seasonal nature of our regulated sales, we generate the smallest proportion of cash from operations during the warmer months, when sales volumes decrease considerably. Most of our construction activity takes place during these warmer months. As a result, we meet our cash needs for operations and construction during the warmer non-heating months partially through short-term borrowings.

We made capital expenditures of $9,195,000, $9,422,000 and $7,070,000 during the fiscal years ended 2003, 2002 and 2001, respectively. These capital expenditures were for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

We generate internally only a portion of the cash necessary for our capital expenditure requirements. We finance the balance of our capital expenditures on an interim basis through a short-term line of bank credit. Our current available line of credit is $40,000,000, of which $1,031,000 was borrowed at June 30, 2003. The line of credit is with Branch Banking and Trust Company, and extends through October 31, 2003. We intend to pursue renewal or to enter into a new agreement and seek substantially the same terms as the existing agreement.

We periodically repay our short-term borrowings under our line of credit by using the net proceeds from the sale of long-term debt and equity securities. For example, during February, 2003, we issued $20,000,000 aggregate principal amount of 7.00% Debentures due 2023. The net proceeds of the offering were $19,181,000. We used the net proceeds to redeem $14,806,000 aggregate principal amount of our 8.30% Debentures due 2026 and to pay down our short-term notes payable. During May, 2003, we used the net proceeds of $12,493,000 from our sale of 600,000 shares of common stock to pay down our short-term notes payable. We will use additional borrowings under our existing line of credit to help meet working capital and capital expenditure needs as required.

Below, we summarize our primary cash flows during the last three fiscal years indicated:

	2003	2002	2001
Provided by operating activities	**$15,542,077**	$10,511,896	$ 2,652,572
Used in investing activities	**(9,195,099)**	(9,421,765)	(7,069,713)
Provided by (used in) financing activities	**(5,152,200)**	(1,028,996)	4,185,248
Increase (decrease) in cash and cash equivalents	**$ 1,194,778**	$ 61,135	$ (231,893)

For the year ended June 30, 2003, we had a $1,195,000 increase in cash and cash equivalents compared to a $61,000 increase in cash and cash equivalents for the year ended June 30, 2002. This variation resulted from an increase in cash provided by operating activities and a decrease in cash used in investing activities, partially offset by increases in cash used in financing activities. The increase in cash provided by operating activities was largely due to changes in accounts payable, deferred income taxes and gas in storage, offset by changes in accounts receivable, prepayments and deferred gas costs. The decrease in cash used in investing activities resulted from decreased capital expenditures. The increase in cash used in financing activities is primarily attributable to the repayment of short-term debt, offset by the issuance of additional long-term debt and equity.

For the year ended June 30, 2002, we had a $61,000 increase in cash and cash equivalents compared to a $232,000 decrease in cash and cash equivalents for the year ended June 30, 2001. This variation resulted from an increase in cash provided by operating activities, offset by increases in cash used in investing and financing activities. The increase in cash provided by operating activities was largely due to changes in deferred recovery of gas costs, accounts receivable, accounts payable and deferred income taxes. The increase in cash used in investing activities resulted from increased capital expenditures. Cash was used in financing activities in 2002 since dividends paid on common stock and repayments of long-term debt exceeded borrowings from the short-term line of credit. Cash was provided by financing activities in 2001 since borrowings from the short-term line of credit exceeded dividends paid on common stock and repayments of long-term debt.

Cash provided by our operating activities primarily consists of net income adjusted for non-cash items, including depreciation, depletion, amortization, deferred income taxes and changes in working capital. We expect that internally generated cash, 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.

Results of Operations

For meaningful analysis of our revenue and expense variations, the variation amounts and percentages presented below for regulated and non-regulated revenues and expenses include intersegment transactions. These intersegment revenues and expenses whose variations are also disclosed in the following tables, are eliminated in the consolidated statements of income.

Operating Revenues

In the following table we set forth variations in our revenues for the last two fiscal years:

	2003 compared to 2002	2002 compared to 2001
Increase (decrease) in our regulated revenues		
Gas rates	$ 3,030,000	$ (1,742,000)
Weather normalization adjustment	(1,619,000)	1,936,000
Sales volumes	5,685,000	(9,192,000)
On-system transportation	47,000	(69,000)
Off-system transportation	340,000	406,000
Other	(3,000)	(50,000)
Total	$ 7,480,000	$ (8,711,000)
Increase (decrease) in our non-regulated revenues		
Gas rates	$ 4,519,000	$ (7,265,000)
Sales volumes	(1,106,000)	(5,840,000)
Other	7,000	(1,000)
Total	$ 3,420,000	$(13,106,000)
Total increase (decrease) in our revenues	10,900,000	(21,817,000)
Decrease in our intersegment revenues	1,610,000	6,917,000
Increase (decrease) in our consolidated revenues	$12,510,000	$(14,900,000)
Percentage increase (decrease) in our regulated volumes		
Gas sales	15.3	(19.1)
On-system transportation	8.9	2.0
Off-system transportation	28.0	50.9
Percentage decrease in non-regulated gas sales volumes	(7.5)	(20.1)

Heating degree days billed were 106% of normal thirty year average temperatures for fiscal 2003, as compared with 89% of normal temperatures for 2002 and 107% of normal for 2001. 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.

The increase in operating revenues for 2003 of $12,510,000 was primarily due to the 15.3% increase in our regulated volumes because of the significantly colder weather in 2003, as well as the 23.7% increases in gas costs reflected in higher sales prices. This increase, however, was offset to some extent because unusually cold temperatures caused us to adjust our rates downward under our authorized weather normalization tariff. The decrease in our non-regulated sales volumes and our intersegment revenues is a result of the non-regulated segment discontinuing the practice of selling gas to the regulated segment effective January 1, 2002.

The decrease of $14,900,000 in our operating revenues for 2002 was primarily attributable to decreased sales volumes and decreased gas rates. Sales volumes decreased due to warmer winter weather in 2002. Gas rates decreased due to lower gas prices. This increase, however, was offset to some extent, because unusually warm temperatures enabled us to adjust our rates upward under our authorized weather normalization tariff.

Operating Expenses

In the following table we set forth variations in our purchased gas expense for the last two fiscal years:

	2003 compared to 2002	2002 compared to 2001
Increase (decrease) in our regulated gas expense		
Gas rates	$ 3,068,000	$ (2,607,000)
Purchase volumes	3,784,000	(5,157,000)
Total	$ 6,852,000	$ (7,764,000)
Increase (decrease) in our non-regulated gas expense		
Gas rates	$ 3,273,000	$ (8,169,000)
Purchase volumes	(922,000)	(5,400,000)
Transportation expense	81,000	(194,000)
Total	$ 2,432,000	$(13,763,000)
Decrease (increase) in our intersegment gas expense	$ 1,610,000	$ 6,917,000
Increase (decrease) in our consolidated gas expense	$ 10,894,000	$(14,610,000)

The increase in purchased gas expense for 2003 of $10,894,000 was due primarily to the 23.7% increase in the cost of gas purchased for regulated sales and the 15.3% increase in regulated volumes sold.

The decrease in purchased gas expense for 2002 of $14,610,000 was due primarily to the 24.2% decrease in the cost of gas purchased for regulated sales and the 20.1% decrease in non-regulated volumes sold.

The increase in operation and maintenance expense of $972,000 for the year ended June 30, 2003 was primarily due to an increase in bad debt expense resulting from higher gas prices and colder winter weather, as well as an increase in employee benefit costs.

The increase in taxes other than income taxes for the year ended June 30, 2003 of $155,000 was primarily due to increased property taxes.

Basic and Diluted Earnings Per Common Share

For the fiscal years ended June 30, 2003, 2002 and 2001, 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, our Employee Stock Purchase Plan and our May, 2003 common stock offering.

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.

Pension Benefits

Our reported costs of providing pension benefits (as described in Note 4(a) of the Notes to 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.

In accordance with Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions, changes in pension obligations associated with the above factors may not be immediately recognized as pension costs on the income statement, but may be deferred and amortized in the future over the average remaining service period of active plan participants to the extent that Statement 87 recognition provisions are triggered. For the years ended June 30, 2003, 2002 and 2001, we recorded pension costs for our defined benefit pension plan of $535,000, $428,000 and $237,000, respectively.

Effective April 1, 2002, our Board of Directors adopted a plan amendment which enhanced the formula for benefits paid under the Company's Defined Benefit Retirement Plan. In September, 2002, our Board of Directors approved an amendment to the plan effective November 1, 2002. The plan amendment reduced the formula for benefits paid under the plan for future service and restricted participants from takinglump-sum distributions from the plan.

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. In establishing our expected long-term rate of return assumption, we utilize analysis prepared by our investment manager. Our expected long-term rate of return on pension plan assets is 8.0% and is based on our targeted asset allocation assumption of approximately 60 percent equity investments and approximately 40 percent fixed income investments. Our approximately 60 percent equity investment target includes allocations to domestic, international, and emerging markets managers. 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 cost 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 our assumed long-term rate of return of 8 percent, discount rate of 6.25 percent, and various other assumptions, we estimate that our pension costs associated with our defined benefits pension plan will increase from $535,000 in 2003 to approximately $725,000 in 2004. Modifying the expected long-term rate of return on our pension plan assets by .25 percent would change pension costs for 2004 by approximately $20,000. Modifying the discount rate assumption by .25 percent would change 2004 pension costs by approximately $65,000.

Factors That May Affect Future Results

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that are not statements of historical facts. We have attempted to identify these statements by using words such as "estimates", "attempts", "expects", "monitors", "plans", "anticipates", "intends", "continues", "believes", "seeks", "strives" and similar expressions.

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

- our operational plans and strategies,
- 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, and
- dividends

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 in 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, cost and availability of interstate pipeline capacity, 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, and
- changes in accounting principles and tax laws or the application of such principles and laws to us.

Contractual Obligations

The following is provided to summarize our contractual cash obligations for the periods after June 30, 2003:

	Payments Due by Period				
	2004	2005-2007	2008	After 2008	Total
Long-term debt (a)	$ 1,650,000	$ 4,950,000	$ 1,650,000	$46,773,000	$55,023,000
Operating lease (b)	75,000	211,000	61,000	752,000	1,099,000
Gas purchase obligations	4,351,000	5,748,000	854,000	285,000	11,238,000
Total contractual obligations	$ 6,076,000	$10,909,000	$ 2,565,000	$47,810,000	$67,360,000

(a) See Note 8 of the Notes to Consolidated Financial Statements.

(b) The operating lease amount after June, 2008 includes the present value of leases having an indeterminate life. These leases relate primarily to storage well and compressor station site leases. For the purpose of this calculation we have assumed a 40 year life for these agreements. To the extent that these leases extend beyond 2043, the annual lease payments will be $52,000.

New Accounting Pronouncements

In June, 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 146, entitled Accounting for Costs Associated with Exit or Disposal Activities. This statement requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred and is effective for exit or disposal activities that are initiated after December 31, 2002. We have not committed to any such exit or disposal plan. Accordingly, this new statement will not presently have any impact on us.

In June, 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, entitled Accounting for Asset Retirement Obligations, and Delta adopted this statement effective July 1, 2002. Statement No. 143 addresses financial accounting for legal obligations associated with the retirement of long-lived assets. Upon adoption of this statement, we recorded $178,000 of asset retirement obligations in the balance sheet primarily representing the current estimated fair value of our obligation to plug oil and gas wells at the time of abandonment. Of this amount, $47,000 was recorded as incremental cost of the underlying property, plant and equipment. The cumulative effect on earnings of adopting this new statement was a charge to earnings of $88,000 (net of income taxes of $55,000), representing the cumulative amounts of depreciation and depletion expenses and changes in the asset retirement obligation due to the passage of time for historical accounting periods. The adoption of the new standard did not have a significant impact on income before cumulative effect of a change in accounting principle for the year ended June 30, 2003. Pro forma net income and earnings per share have not been presented for the years ended June 30, 2002 and 2001 because the pro forma application of Statement No. 143 to prior periods would result in pro forma net income and earnings per share not materially different from the actual amounts reported for those periods in the accompanying consolidated statements of income. We also have asset retirement obligations which have indeterminate settlement dates. These obligations, relating to gas wells and lines at our storage facility and compressor station sites, are not recorded until an estimated range of potential settlement dates is known, according to Statement No. 143. As allowed for ratemaking purposes and Statement of Financial Accounting Standards No. 71, entitled Accounting for the Effects of Certain Types of Regulation, 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. Approximately $700,000 of accrued cost of removal is recorded in the accumulated provision for depreciation on the accompanying balance sheet as of June 30, 2003.

In August, 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 144, entitled Accounting for the Impairment or Disposal of Long-Lived Assets. Statement No. 144 addresses accounting and reporting for the impairment or disposal of long-lived assets. Statement No. 144 was effective July 1, 2002. There was no impact of implementation on our financial position and results of operations.

In December, 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 148, entitled Accounting for Stock-Based Compensation. Statement No. 148 was effective for the June 30, 2003 fiscal year. There was no impact of implementation on our financial position and results of operations.

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 months 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. 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.

As a part of our unregulated transportation activities, we periodically contract with our transportation customers to acquire gas that we will transport to these customers. At the time we make a sales commitment to one of these customers, we attempt to cover this position immediately with gas purchase commitments that match the terms of the related sales contract in order to minimize our price volatility risk.

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" 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 notes payable. The interest rate on our current short-term line of credit with Branch Banking and Trust Company is benchmarked to the Monthly London Interbank Offered Rate. The balance on our short-term line of credit was $1,031,099 on June 30, 2003 and $19,355,000 on June 30, 2002. Based on the amount of our outstanding short-term line of credit on June 30, 2003, a one percent (one hundred basis point) increase in our average interest rate would result in a decrease in our annual pre-tax net income of $10,000.

Item 8. Financial Statements and Supplementary Data

Schedules other than those listed above are omitted because they are not required, 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 controls and other procedures that are designed to ensure that information required to be disclosed in Company reports filed or submitted under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in Company reports filed under the Exchange Act is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

As required by Rule 13a-15 under the Exchange Act, within the 90 days prior to the filing date of this report, the Company carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures. This evaluation was carried out under the supervision and with the participation of the Company's management, including the Company's President and Chief Executive Officer along with the Company's Chief Financial Officer. Based upon that evaluation, the Company's President and Chief Executive Officer along with the Company's Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective. There have been no significant changes in the Company's internal controls or in other factors which could significantly affect internal controls subsequent to the date the Company carried out its evaluation.

PART III

Item 10. Directors and Executive Officers of the Registrant

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management

Item 13. Certain Relationships and Related Transactions

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) not 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, 11, 12, 13 and 14 is incorporated herein by reference to the definitive proxy statement. Neither the report on Executive Compensation nor the performance graph included in the Company's definitive proxy statement shall be deemed incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(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 are incorporated herein by reference to Exhibit 4(a) to Delta's Registration Statement on Form S-2 (Reg. No. 333-0431) dated April 4, 2003.

3(ii) Registrant's Amended and Restated By-Laws (dated November 21, 2002) are incorporated herein by reference to Exhibit 3(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended December 31, 2002.

4(a) The Indenture dated September 1, 1993 in respect of 6 5/8% Debentures due October 1, 2023, is incorporated herein by reference to Exhibit 4(e) to Delta's Form S-2 (Reg. No. 33-68274) dated September 2, 1993.

4(b) The Indenture dated March 1, 1998 in respect of 7.15% Debentures due April 1, 2018, is incorporated herein by reference to Exhibit 4(d) to Delta's Form S-2 (Reg. No. 333-47791) dated March 11, 1998.

4(c) Indenture dated January 1, 1003 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 five officers, those being John B. Brown, Johnny L. Caudill, John F. Hall, 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) Agreement between Registrant and Harrison D. Peet, Chairman of the Board, is incorporated herein by reference to Exhibit 10(l) to Registrant's Form 10-Q (File No. 000-08788) for the period ended March 31, 2000.

10(c) Gas Sales Agreement, dated May 1, 2000, by and between the Registrant and Woodward Marketing, L.L.C. is incorporated herein by reference to Exhibit 10(d) to Registrant's Form S-2 (Reg. No. 333-100852) dated February 7, 2003.

10(d) Gas Sales Agreement, dated May 1, 2003, by and between the Registrant and Woodward 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.
12	Computation of the Consolidated Ratio of Earnings to Fixed Charges.
16	Letter dated May 22, 2002 from Arthur Andersen LLP to the Securities and Exchange Commission is incorporated herein by reference to Exhibit 16 to Registrant's Form 8-K (File No. 000-08788) dated May 22, 2002.
21	Subsidiaries of the Registrant.
23	Independent Auditors' Consent.
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2	Certification of the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1	Written statement of the Chief Executive Officer, pursuant to 18 U.S.C. Section 1350.
32.2	Written statement of the Principal Financial Officer, pursuant to 18 U.S.C. Section 1350.

(b) Reports on 8-K.

The Company did not file any reports on Form 8-K during the fourth quarter of the recently completed fiscal year.

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 5th day of September, 2003.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings
Glenn R. Jennings, 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)	President, Chief Executive Officer and Vice Chairman of the Board	September 5, 2003

(ii) Principal Financial Officer:

/s/John F. Hall (John F. Hall)	Vice-President - Finance, Secretary and Treasurer	September 5, 2003

(iii) Principal Accounting Officer:

/s/John B. Brown (John B. Brown)	Controller	September 5, 2003

(iv) A Majority of the Board of Directors:

/s/H. D. Peet (H. D. Peet)	Chairman of the Board	September 5, 2003
/s/Donald R. Crowe (Donald R. Crowe)	Director	September 5, 2003
/s/Jane Hylton Green (Jane Hylton Green)	Director	September 5, 2003
(Lanny D. Greer)	Director	September 5, 2003

/s/Billy Joe Hall (Billy Joe Hall)	Director	September 5, 2003
/s/Michael J. Kistner (Michael J. Kistner)	Director	September 5, 2003
/s/Lewis N. Melton (Lewis N. Melton)	Director	September 5, 2003
(Arthur E. Walker, Jr.)	Director	September 5, 2003
/s/Michael R. Whitley (Michael R. Whitley)	Director	September 5, 2003

Management's Statement of Responsibility for Financial Reporting and Accounting

Management is responsible for the preparation, presentation and integrity of the financial statements and other financial information in this report. In preparing financial statements in conformity with accounting principles generally accepted in the United States, management is required to make estimates and assumptions that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ from these estimates.

The Company maintains a system of accounting and internal controls which management believes provides reasonable assurance that the accounting records are reliable for purposes of preparing financial statements and that the assets are properly accounted for and protected.

The Board of Directors pursues its oversight role for these financial statements through its Audit Committee, which consists of four outside directors. The Audit Committee meets periodically with management to review the work and monitor the discharge of their responsibilities. The Audit Committee also meets periodically with the Company's internal auditor as well as Deloitte & Touche LLP, the independent auditors, who have full and free access to the Audit Committee, with or without management present, to discuss internal accounting control, auditing and financial reporting matters.

Glenn R. Jennings
President & Chief Executive Officer

John F. Hall
Vice President - Finance,
Secretary & Treasurer

John B. Brown
Controller

INDEPENDENT AUDITORS' REPORT

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. and subsidiaries (the "Company") as of June 30, 2003 and 2002, and the related consolidated statements of capitalization, income, cash flows and changes in shareholders' equity for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The financial statements of the Company for the year ended June 30, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated August 10, 2001.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 Delta Natural Gas Company, Inc. and subsidiaries as of June 30, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The additional information listed in Schedule II of the Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the years ended June 30, 2003 and 2002 is presented for the purpose of additional analysis and is not a required part of the 2003 and 2002 basic financial statements. This additional information is the responsibility of the Company's management. Such information has been subjected to the auditing procedures applied in our audits of the 2003 and 2002 basic financial statements and, in our opinion, is fairly stated in all material respects when considered in relation to the 2003 and 2002 basic financial statements taken as a whole. The additional information for the year ended June 30, 2001, was audited by other auditors who have ceased operations. Those auditors expressed an opinion, in their report dated August 10, 2001, that the 2001 additional information, when considered in relation to the 2001 basic financial statements taken as a whole, presented fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Cincinnati, Ohio
August 15, 2003

Report of Previous Independent Public Accountants

THE FOLLOWING REPORT IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of DELTA NATURAL GAS COMPANY, INC. (a Kentucky corporation) and subsidiary companies as of June 30, 2001 and 2000, and the related consolidated statements of income, cash flows and changes in shareholders' equity for each of the three years in the period ended June 30, 2001. These financial statements and the schedule referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Delta Natural Gas Company, Inc. and subsidiary companies as of June 30, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2001, in conformity with accounting principles generally accepted in the United States.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule listed in the Index to Consolidated Financial Statements and Schedule is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Louisville, Kentucky
August 10, 2001

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Income

For the Years Ended June 30,	**2003**	2002	2001
Operating Revenues	**$ 68,380,263**	$ 55,870,219	$ 70,770,156
Operating Expenses			
Purchased gas	**$ 40,991,670**	$ 30,097,664	$ 44,707,739
Operation and maintenance	**10,657,552**	9,685,746	9,844,728
Depreciation and depletion	**4,281,207**	4,080,944	3,840,450
Taxes other than income taxes	**1,510,111**	1,354,913	1,423,020
Income tax expense (Note 3)	**2,413,357**	2,249,500	2,232,500
Total operating expenses	**$ 59,853,897**	$ 47,468,767	$ 62,048,437
Operating Income	**$ 8,526,366**	$ 8,401,452	$ 8,721,719
Other Income and Deductions, Net	**47,641**	17,018	31,141
Interest Charges			
Interest on long-term debt	**3,858,082**	3,728,847	3,775,856
Other interest	**582,955**	891,750	1,179,949
Amortization of debt expense	**193,993**	161,160	161,160
Total interest charges	**$ 4,635,030**	$ 4,781,757	$ 5,116,965
Income Before Cumulative Effect of a Change in Accounting Principle	**$ 3,938,977**	$ 3,636,713	$ 3,635,895
Cumulative Effect of a Change in Accounting Principle, net of income taxes of $55,000 (Note 2)	**(88,370)**	--	--
Net Income	**$ 3,850,607**	$ 3,636,713	$ 3,635,895
Basic and Diluted Earnings Per Common Share Before Cumulative Effect of a Change in Accounting Principle	**$ 1.49**	$ 1.45	$ 1.47
Cumulative Effect of a Change in Accounting Principle	**(.03)**	--	--
Basic and Diluted Earnings Per Common Share	**$ 1.46**	$ 1.45	$ 1.47
Weighted Average Number of Common Shares Outstanding (Basic and Diluted)	**2,641,829**	2,513,804	2,477,983
Dividends Declared Per Common Share	**$ 1.18**	$ 1.16	$ 1.14

The accompanying notes to consolidated financial statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Cash Flows

For the Years Ended June 30,	**2003**	2002	2001
Cash Flows From Operating Activities			
Net income	**$ 3,850,607**	$ 3,636,713	$ 3,635,895
Adjustments to reconcile net income to net cash from operating activities			
Cumulative effect of a change in accounting principle	**88,370**	--	--
Depreciation, depletion and amortization	**4,461,812**	4,354,396	4,047,715
Deferred income taxes and investment tax credits	**1,991,258**	1,110,916	2,332,458
Other - net	**675,807**	595,894	700,091
(Increase) decrease in assets			
Accounts receivable	**(1,682,752)**	1,767,741	(1,860,926)
Gas in storage	**178,076**	(556,871)	(1,665,124)
Deferred gas cost	**(215,765)**	368,648	(4,518,953)
Materials and supplies	**(28,723)**	69,663	(129,278)
Prepayments	**(78,355)**	681,195	(690,662)
Other assets	**128,163**	(89,615)	(333,402)
Increase (decrease) in liabilities			
Accounts payable	**6,546,104**	(1,524,216)	1,647,056
Refunds due customers	**(73,973)**	35,653	(5,708)
Accrued taxes	**178,207**	(44,503)	(521,190)
Other current liabilities	**(170,415)**	128,283	11,340
Other liabilities	**(306,344)**	(22,001)	3,260
Net cash provided by operating activities	**$15,542,077**	$ 10,511,896	$ 2,652,572
Cash Flows From Investing Activities			
Capital expenditures	**$ (9,195,099)**	$ (9,421,765)	$ (7,069,713)
Net cash used in investing activities	**$ (9,195,099)**	$ (9,421,765)	$ (7,069,713)

The accompanying notes to consolidated financial statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Cash Flows (continued)

For the Years Ended June 30,	2003	2002	2001
Cash Flows From Financing Activities			
Dividends on common stock	**$ (3,185,900)**	$ (2,916,418)	$ (2,825,267)
Issuance of common stock, net	**13,096,249**	707,422	646,514
Issuance of long-term debt	**20,000,000**	--	--
Long-term debt issuance expense	**(819,408)**	--	--
Repayment of long-term debt	**(15,919,240)**	(1,375,000)	(810,999)
Issuance of notes payable	**84,556,011**	36,860,000	52,415,000
Repayment of notes payable	**(102,879,912)**	(34,305,000)	(45,240,000)
Net cash provided by (used in) financing activities	**$ (5,152,200)**	$ (1,028,996)	$ 4,185,248
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 1,194,778**	$ 61,135	$ (231,893)
Cash and Cash Equivalents, Beginning of Year	**225,236**	164,101	395,994
Cash and Cash Equivalents, End of Year	**$ 1,420,014**	$ 225,236	$ 164,101
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	**$ 4,701,320**	$ 4,636,051	$ 4,970,327
Income taxes (net of refunds)	**$ 355,308**	$ 1,130,566	$ 395,737

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

As of June 30,	2003	2002
Assets		
Gas Utility Plant, at cost	**$163,745,044**	$156,305,063
Less – Accumulated provision for depreciation	**(52,383,975)**	(49,142,976)
Net gas plant	**$111,361,069**	$107,162,087
Current Assets		
Cash and cash equivalents	**$ 1,420,014**	$ 225,236
Accounts receivable, less accumulated provisions for doubtful accounts of $350,000 and $165,000 in 2003 and 2002, respectively	**4,566,777**	2,884,025
Gas in storage, at average cost	**5,090,440**	5,216,772
Deferred gas costs	**4,291,824**	4,076,059
Materials and supplies, at first-in, first-out cost	**552,479**	523,756
Prepayments	**467,149**	388,794
Total current assets	**$ 16,388,683**	$ 13,314,642
Other Assets		
Cash surrender value of officers' life insurance (face amount of $1,236,009)	**$ 356,137**	$ 344,687
Note receivable from officer	**134,000**	158,000
Unamortized debt expense, prepaid pension and other (Notes 4 and 8)	**4,333,900**	5,507,669
Total other assets	**$ 4,824,037**	$ 6,010,356
Total assets	**$132,573,789**	$126,487,085

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,	2003	2002
Liabilities and Shareholders' Equity		
Capitalization (See Consolidated Statements of Capitalization)		
Common shareholders' equity		
Common shares	$ 3,166,940	$ 2,530,079
Premium on common shares	43,462,433	30,330,330
Capital stock expense	(2,598,146)	(1,925,431)
Accumulated other comprehensive loss	(2,050,636)	--
Retained earnings	3,912,006	3,247,299
Total common shareholders' equity	$ 45,892,597	$ 34,182,277
Long-term debt (Notes 8 and 9)	53,373,000	48,600,000
Total capitalization	$ 99,265,597	$ 82,782,277
Current Liabilities		
Notes payable (Note 7)	$ 1,031,099	$ 19,355,000
Current portion of long-term debt (Notes 8 and 9)	1,650,000	1,750,000
Accounts payable	10,624,087	4,077,983
Accrued taxes	797,224	673,873
Refunds due customers	--	73,973
Customers' deposits	442,315	440,568
Accrued interest on debt	902,673	1,162,956
Accrued vacation	576,388	558,066
Other accrued liabilities	587,158	503,178
Total current liabilities	$ 16,610,944	$ 28,595,597
Deferred Credits and Other		
Deferred income taxes	$ 14,844,431	$ 14,078,273
Investment tax credits	364,600	404,600
Regulatory liabilities (Note 1)	491,325	562,025
Minimum pension liability (Note 4)	716,780	--
Advances for construction and other	280,112	64,313
Total deferred credits and other	$ 16,697,248	$ 15,109,211
Commitments and Contingencies (Note 11)		
Total liabilities and shareholders' equity	$132,573,789	$126,487,085

The accompanying notes to consolidated financial statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

For the Years Ended June 30,	2003	2002	2001
Common Shares			
Balance, beginning of year	$ 2,530,079	$ 2,495,679	$ 2,459,067
Common stock offering, $1.00 par value of 600,000 shares issued in 2003	600,000	--	--
Dividend reinvestment and stock purchase plan, $1.00 par value of 30,821, 28,506 and 28,958 shares issued in 2003, 2002 and 2001, respectively	30,821	28,506	28,958
Employee stock purchase plan and other, $1.00 par value of 6,040, 5,894 and 7,654 shares issued in 2003, 2002 and 2001, respectively	6,040	5,894	7,654
Balance, end of year	$ 3,166,940	$ 2,530,079	$ 2,495,679
Premium on Common Shares			
Balance, beginning of year	$ 30,330,330	$ 29,657,308	$ 29,038,995
Premium on issuance of common shares			
Common stock offering	12,360,000	--	--
Dividend reinvestment and stock purchase plan	644,906	561,547	503,897
Employee stock purchase plan and other	127,197	111,475	114,416
Balance, end of year	$ 43,462,433	$ 30,330,330	$ 29,657,308
Capital Stock Expense			
Balance, beginning of year	$ (1,925,431)	$ (1,925,431)	$ (1,917,020)
Common stock offering	(672,715)	--	--
Dividend reinvestment and stock purchase plan	--	--	(8,411)
Balance, end of year	$ (2,598,146)	$ (1,925,431)	$ (1,925,431)
Accumulated Other Comprehensive Loss			
Balance, beginning of year	$ --	$ --	$ --
Minimum pension liability adjustment, net of tax benefit of $1,335,800 (Note 4)	(2,050,636)	--	--
Balance, end of year	$ (2,050,636)	$ --	$ --

The accompanying notes to consolidated financial statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity (continued)

For the Years Ended June 30,	2003	2002	2001
Retained Earnings			
Balance, beginning of year	$ 3,247,299	$ 2,527,004	$ 1,716,376
Net income	3,850,607	3,636,713	3,635,895
Cash dividends declared on common shares (See Consolidated Statements of Income for rates)	(3,185,900)	(2,916,418)	(2,825,267)
Balance, end of year	$ 3,912,006	$ 3,247,299	$ 2,527,004
Common Shareholders' Equity			
Balance, beginning of year	$ 34,182,277	$ 32,754,560	$ 31,297,418
Comprehensive income			
Net income	3,850,607	3,636,713	3,635,895
Other comprehensive loss	(2,050,636)	--	--
Comprehensive income	$ 1,799,971	$ 3,636,713	$ 3,635,895
Issuance of common stock	$ 13,096,249	$ 707,422	$ 646,514
Dividends on common stock	(3,185,900)	(2,916,418)	(2,825,267)
Balance, end of year	$ 45,892,597	$ 34,182,277	$ 32,754,560

The accompanying notes to consolidated financial statements are an integral part of these statements.

Delta Natural Gas Company, Inc. and Subsidiary Companies

Consolidated Statements of Capitalization

As of June 30,	2003	2002
Common Shareholders' Equity		
Common shares, par value $1.00 per share (Notes 4 and 5)		
Authorized 6,500,000 shares		
Issued and outstanding 3,166,940 and 2,530,079 shares in 2003 and 2002, respectively	$ 3,166,940	$ 2,530,079
Premium on common shares	43,462,433	30,330,330
Capital stock expense	(2,598,146)	(1,925,431)
Accumulated other comprehensive loss	(2,050,636)	--
Retained earnings (Note 8)	3,912,006	3,247,299
Total common shareholders' equity	$ 45,892,597	$ 34,182,277
Long-Term Debt (Notes 8 and 9)		
Debentures, 6 5/8%, due 2023	$ 11,051,000	$ 11,445,000
Debentures, 7.0%, due 2023	20,000,000	--
Debentures, 7.15%, due 2018	23,972,000	24,089,000
Debentures, 8.3%, due 2026	--	14,816,000
Total debt	$ 55,023,000	$ 50,350,000
Less amounts due within one year, included in current liabilities	(1,650,000)	(1,750,000)
Total long-term debt	$ 53,373,000	$ 48,600,000
Total capitalization	$ 99,265,597	$ 82,782,277

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") sells natural gas to approximately 40,000 customers on our distribution system in central and southeastern Kentucky. We have three wholly-owned subsidiaries. Delta Resources, Inc. ("Delta Resources") 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 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. Certain reclassifications have been made to prior-period amounts to conform to the 2003 presentation.

(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) 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 2.9%, 2.9%, and 2.8% of average depreciable plant for 2003, 2002 and 2001, respectively.

(d) 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 and also for the net cost of removal.

(e) 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 prudent gas costs incurred. 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.

(f) Revenue Recognition We record revenues as billed to 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 cycle meter reading to the month-end is unbilled. Revenue is shown net of excise taxes collected from customers.

(g) Revenues and Customer Receivables We serve 40,000 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.

(h) 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.

(i) Rate Regulated Basis of Accounting Our regulated operations follow the accounting and reporting requirements of SFAS No. 71, "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 sheet (regulatory assets) and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future (regulatory liabilities). The amounts recorded as regulatory assets and regulatory liabilities are as follows:

Regulatory assets ($000)	**2003**	2002
Deferred gas cost	**4,292**	4,076
Loss on extinguishment of debt	**2,386**	1,337
Rate case and gas audit expense	**--**	116
Total regulatory assets	**6,678**	5,529
Regulatory liabilities ($000)		
Refunds from suppliers that are due customers	**--**	74
Regulatory liability for deferred income taxes	**491**	562
Total regulatory liabilities	**491**	636

We are currently earning a return on loss on extinguishment of debt and rate case expenses. 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.

(j) 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.

(2) New Accounting Pronouncements

In June, 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 146, entitled Accounting for Costs Associated with Exit or Disposal Activities. This statement requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred and is effective for exit or disposal activities that are initiated after December 31, 2002. We have not committed to any such exit or disposal plan. Accordingly, this new statement will not presently have any impact on us.

In June, 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, entitled Accounting for Asset Retirement Obligations, and Delta adopted this statement effective July 1, 2002. Statement No. 143 addresses financial accounting for legal obligations associated with the retirement of long-lived assets. Upon adoption of this statement, we recorded $178,000 of asset retirement obligations in the balance sheet primarily representing the current estimated fair value of our obligation to plug oil and gas wells at the time of abandonment. Of this amount, $47,000 was recorded as incremental cost of the underlying property, plant and equipment. The cumulative effect on earnings of adopting this new statement was a charge to earnings of $88,000 (net of income taxes of $55,000), representing the cumulative amounts of depreciation and depletion expenses and changes in the asset retirement obligation due to the passage of time for historical accounting periods. The adoption of the new standard did not have a significant impact on income before cumulative effect of a change in accounting principle for the year ended June 30, 2003. Pro forma net income and earnings per share have not been presented for the years ended June 30, 2002 and 2001 because the pro forma application of Statement No. 143 to prior periods would result in pro forma net income and earnings per share not materially different from the actual amounts reported for those periods in the accompanying consolidated statements of income. We also have asset retirement obligations which have indeterminate settlement dates. These obligations, relating to gas wells and lines at our storage facility and compressor station sites, are not recorded until an estimated range of potential settlement dates is known, according to Statement No. 143. As allowed for ratemaking purposes and Statement of Financial

Accounting Standards No. 71, entitled Accounting for the Effects of Certain Types of Regulation, 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. Approximately $700,000 of accrued cost of removal is recorded in the accumulated provision for depreciation on the accompanying balance sheet as of June 30, 2003.

In August, 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 144, entitled Accounting for the Impairment or Disposal of Long-Lived Assets. Statement No. 144 addresses accounting and reporting for the impairment or disposal of long-lived assets. Statement No. 144 was effective July 1, 2002. There was no impact of implementation on our financial position and results of operations.

In December, 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 148, entitled Accounting for Stock-Based Compensation. Statement No. 148 was effective for the June 30, 2003 fiscal year. There was no impact of implementation on our financial position and results of operations.

(3) 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 cost recoveries 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 are computed using tax rates that will be in effect when the book and tax temporary differences reverse. The change in tax rates applied to accumulated deferred income taxes may not be immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the future revenue requirement impact from these deferred taxes. The temporary differences which gave rise to the net accumulated deferred income tax liability for the periods are as follows:

	2003	2002
Deferred Tax Liabilities		
Accelerated depreciation	**$ 14,942,631**	$ 13,436,373
Deferred gas cost	**1,692,900**	1,364,800
Accrued pension	**2,600**	1,104,200
Debt issuance expense	**614,500**	406,300
Total	**$ 17,252,631**	$ 16,311,673
Deferred Tax Assets		
Alternative minimum tax credits	**$ 1,408,900**	$ 1,365,200
Regulatory liabilities	**193,800**	221,700
Investment tax credits	**143,800**	159,600
Other	**661,700**	486,900
Total	**$ 2,408,200**	$ 2,233,400
Net accumulated deferred income tax liability	**$ 14,844,431**	$ 14,078,273

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

	2003	2002	2001
Components of Income Tax Expense			
Current			
Federal	**$ 258,700**	$ 776,200	$ (77,000)
State	**64,200**	296,100	(71,700)
Total	**$ 322,900**	$ 1,072,300	$ (148,700)
Deferred	**2,090,457**	1,177,200	2,381,200
Income tax expense	**$ 2,413,357**	$ 2,249,500	$ 2,232,500

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

	2003	2002	2001
Statutory federal income tax rate	**34.0%**	34.0 %	34.0 %
State income taxes net of federal benefit	**5.2**	5.3	5.4
Amortization of investment tax credits	**(0.6)**	(0.8)	(0.9)
Other differences – net	**(0.3)**	(0.2)	(0.3)
Effective income tax rate	**38.3%**	38.3 %	38.2 %

(4) 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. The following table provides a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ended March 31, 2003, and a statement of the funded status as of March 31 of both years, as recognized in the Company's consolidated balance sheets at June 30:

	2003	2002
Change in Benefit Obligation		
Benefit obligation at beginning of year	**$ 10,681,119**	$ 8,486,103
Service cost	**601,607**	518,496
Interest cost	**636,649**	657,126
Amendments	**(2,807,300)**	1,514,620
Actuarial (gain) loss	**692,436**	(84,009)
Benefits paid	**(589,586)**	(411,217)
Benefit obligation at end of year	**$ 9,214,925**	$ 10,681,119

	2003	2002
Change in Plan Assets		
Fair value of plan assets at beginning of year	**$ 9,219,679**	$ 9,073,398
Actual return (loss) on plan assets	**(1,198,684)**	14,243
Employer contribution	**878,913**	543,255
Benefits paid	**(589,586)**	(411,217)
Fair value of plan assets at end of year	**$ 8,310,322**	$ 9,219,679
Funded status	**$ (904,603)**	$ (1,461,440)
Unrecognized net actuarial loss	**4,858,741**	2,272,764
Unrecognized prior service cost	**(1,284,482)**	1,514,620
Minimum pension liability adjustment	**(3,386,436)**	--
Net (minimum pension liability) pension asset	**$ (716,780)**	$ 2,325,944

Effective April 1, 2002, our Board of Directors adopted a plan amendment which enhanced the formula for benefits paid under our Company's Defined Benefit Retirement Plan. In September, 2002, our Board of Directors approved an amendment to the Plan effective November 1, 2002. The plan amendment reduced the formula for benefits paid under the plan for future service and restricted participants from takinglump-sum distributions from the plan.

The assets of the plan consist primarily of common stocks, bonds and certificates of deposit. Net pension costs for the years ended June 30 include the following:

	2003	2002	2001
Components of Net Periodic Benefit Cost			
Service cost	**$ 601,607**	$ 518,496	$ 487,392
Interest cost	**636,649**	657,125	592,537
Expected return on plan assets	**(756,731)**	(755,307)	(800,303)
Amortization of unrecognized net loss	**61,873**	36,528	--
Amortization of net transition asset	**(8,198)**	(29,262)	(42,394)
Net periodic benefit cost	**$ 535,200**	$ 427,580	$ 237,232
Weighted-Average Assumptions			
Discount rate	**6.25%**	7.50%	7.75%
Expected return on plan assets	**8.00%**	8.00%	8.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%

SFAS No. 106, "Employers' Accounting for Post-Retirement Benefits", and SFAS No. 112, "Employers' Accounting for Post-Employment Benefits", do not affect us as we do not provide post-retirement or post-employment 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 any whole percentage between 2% and 15% of their annual compensation. The Company will match 50% of the employee's contribution up to a maximum Company contribution of 2.5% of the employee's annual compensation. For 2003, 2002, and 2001, Delta's Savings Plan expense was $158,900, $165,500, and $154,600, respectively.

(c) Employee Stock Purchase Plan We have an Employee Stock Purchase Plan ("Stock Plan") under which qualified permanent employees are eligible to participate. Under the terms of the Stock Plan, such employees can contribute on a monthly basis 1% of their annual salary level (as of July 1 of each year) to be used to purchase Delta's common stock. We issue Delta common stock, based upon the fiscal year contributions, using an average of the high and low sale prices of Delta's stock as quoted in NASDAQ's National Market System on the last business day in June and matches those shares so purchased. Our expenses under the stock plan were $53,000, $52,000 and $49,000 for the three years ended June 30, 2003, respectively. Therefore, stock with an equivalent market value of $106,000 was issued in July, 2003. The continuation and terms of the Stock Plan are subject to approval by our Board of Directors on an annual basis. Our Board has continued the Stock Plan through June 30, 2004. Rules approved by the Securities and Exchange Commission will require future equity compensation plans to be approved by shareholders.

(5) 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 30,821, 28,506, and 28,958 shares in 2003, 2002 and 2001, respectively. We reserved 150,000 shares for issuance under the Reinvestment Plan in December, 2000, and as of June 30, 2003 there were 75,445 shares still available for issuance.

(6) Note Receivable From Officer

Delta's note receivable from an officer on the accompanying balance sheet relates to a $160,000 loan made to Glenn R. Jennings, our President & Chief Executive Officer. The loan, secured by real estate owned by Jennings, bears interest at 6%, which Jennings pays monthly. Delta forgives $2,000 of the principal amount for each month of service Jennings completes. The outstanding balance on this loan was $134,000 as of June 30, 2003. In the event Jennings terminates his employment with Delta other than due to a change in control, or Jennings' employment is terminated for cause or as a result of his disability or death, the loan will become immediately due and payable.

(7) Notes Payable and Line of Credit

The current available line of credit with Branch Banking and Trust Company is $40,000,000, of which $1,031,000 and $19,355,000 was borrowed having a weighted average interest rate of 3.07% and 3.67% as of June 30, 2003 and 2002, respectively. The maximum amount borrowed during 2003 and 2002 was $30,690,000 and $29,005,000, respectively. The interest on this line is determined monthly at the London Interbank Offered Rate plus 1% on the used line of credit. The cost of the unused line of credit is 0.30%. The current line of credit must be renewed during October, 2003.

(8) Long-Term Debt

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 deceased holders, up to an aggregate of $400,000 annually for all deceased beneficial owners. The 7.00% Debentures can be redeemed beginning in March, 2007.

In March, 1998 we issued $25,000,000 of 7.15% Debentures that mature in March, 2018. Redemption of up to $25,000 annually will be made on behalf of deceased holders within 60 days of notice, subject to an annual aggregate $750,000 limitation. The 7.15% Debentures can be redeemed by us after April 1, 2003.

In October, 1993 we issued $15,000,000 of 6 5/8% Debentures that mature in October, 2023. Each holder may require redemption of up to $25,000 annually, subject to an annual aggregate limitation of $500,000. Such redemption will also be made on behalf of deceased holders within 60 days of notice, subject to the annual aggregate $500,000 limitation. The 6 5/8% Debentures can be redeemed by us beginning in October, 1998 at a 5% premium, such premium declining ratably until it ceases in October, 2003.

We amortize debt issuance expenses over the life of the related debt on a straight-line basis, which approximates the effective yield method.

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

- Dividend payments cannot be made unless consolidated shareholders' equity of the Company exceeds $25,800,0000 (thus no retained earnings were restricted); and

- We may not assume any additional mortgage indebtedness in excess of $2,000,000 without effectively securing all debentures 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 line of credit and all of the debentures. We were not in default on any of our line of credit or debenture agreements during any period presented.

(9) Fair Values of Financial Instruments

The fair value of our Debentures 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 Debentures at June 30, 2003 and 2002 was estimated to be $59,596,000 and $47,479,000, respectively. The carrying amount in the accompanying consolidated financial statements as of June 30, 2003 and 2002 is $55,023,000 and $50,350,000, respectively.

The carrying amount of our other financial instruments including cash equivalents, accounts receivable, notes receivable, accounts payable and the non-interest bearing promissory note approximate their fair value.

(10) Operating Leases

Our operating leases relate primarily to non-cancelable storage well and compressor station site leases. Rental expense under long-term operating leases was $90,000, $74,000 and $72,000 for the three years ending June 30, 2003, 2002 and 2001, respectively. At June 30, 2003, future rental commitments under these leases totaled $1,099,000. Future rental commitments were payable as follows as of June 30, 2003:

Year ending June 30,	
2004	$ 75,000
2005	71,000
2006	70,000
2007	70,000
2008	61,000
Thereafter	752,000
	$1,099,000

Most of our operating leases have an indeterminate life. For the purpose of this disclosure, we have assumed a 40 year life for such agreements. To the extent that these leases extend beyond 2043, the annual lease payments will be $52,000.

(11) Commitments and Contingencies

We have entered into individual employment agreements with our five officers and an agreement with the Chairman of the Board. 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 $2.6 million would be paid in addition to continuation of specified benefits for up to five years.

(12) Rates

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

We monitor our need to file requests with the Kentucky Public Service Commission for a general rate increase for our retail gas and transportation services. Through these general rate cases, we are able to adjust the sales prices of our retail gas we sell to and transport for our customers.

On December 27, 1999, the Kentucky Public Service Commission approved an annual revenue increase for us of $420,000. We filed this general rate case in July, 1999, and it is our most recent filing of a rate case. The approval of our requests in this rate case included a weather normalization provision that permits us to adjust rates for the billing months of December through April to reflect variations from 30-year average winter temperatures.

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.

During July, 2001, the Kentucky Public Service Commission required an independent audit of our gas procurement activities and the gas procurement activities of four other gas distribution companies as part of its investigation of increases in wholesale natural gas prices and their impact on customers. The Kentucky Public Service Commission indicated that Kentucky distributors had generally developed sound planning and procurement procedures for meeting their customers' natural gas requirements and that these procedures had provided customers with reliable supplies of natural gas at reasonable costs. The Kentucky Public Service Commission noted the events of the prior year, including changes in natural gas wholesale markets. It required the auditors to evaluate distributors' gas planning and procurement strategies in light of the recent more volatile wholesale markets, with a primary focus on a balanced portfolio of gas supply that balances cost issues, price risk and reliability. The auditors were selected by the Kentucky Public Service Commission. The final audit report, dated November 15, 2002, contains 16 procedural and reporting-related recommendations in the areas of gas supply planning, organization, staffing, controls, gas supply management, gas transportation, gas balancing, response to regulatory change and affiliate relations. The report also addresses several general areas for the five gas distribution companies involved in the audit, including Kentucky natural gas price issues, hedging, gas cost recovery mechanisms, budget billing, uncollectible accounts and forecasting. In January, 2003, we responded to the auditors with our comments on action plans they drafted relating to the recommendations. Our first status report on the action plans for the 16 recommendations is due to be filed by us with the Kentucky Public Service Commission by September 30, 2003. We believe that implementation of the recommendations will not result in a significant impact on our financial position or results of operations.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities and communities 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 a local franchise. We hold franchises in four of the cities and seven of the communities we serve. In the other cities and communities we serve, either our franchises have expired, the communities do not have governmental organizations authorized to grant franchises, or the local governments have not required or do not want to offer a franchise. We attempt to acquire or reacquire franchises whenever feasible.

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

(13) 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.

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 the sale and purchase of gas as well as intercompany gas transportation services. Effective January 1, 2002, the non-regulated segment discontinued the practice of selling gas to the regulated segment. This led to a decline in intersegment revenues and expenses for 2002 and 2003. Intersegment transportation revenue and expense is recorded at our tariff rates. Transfer pricing for sales of gas between segments is at cost. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown below for the periods:

($000)	**2003**	2002	2001
Revenues			
Regulated			
External customers	**47,769**	40,370	48,887
Intersegment	**3,131**	3,050	3,244
Total regulated	**50,900**	43,420	52,131
Non-regulated			
External customers	**20,611**	15,500	21,883
Intersegment	**--**	1,691	27,609
Total non-regulated	**20,611**	17,191	49,492
Eliminations for intersegment	**(3,131)**	(4,741)	(30,853)
Total operating revenues	**68,380**	55,870	70,770
Operating Expenses			
Regulated			
Depreciation	**4,163**	3,964	3,797
Income taxes	**1,395**	1,599	1,696
Other	**38,409**	30,486	38,662
Total regulated	**43,967**	36,049	44,155
Non-regulated			
Depreciation	**150**	117	43
Income taxes	**963**	651	536
Other	**17,905**	15,393	48,167
Total non-regulated	**19,018**	16,161	48,746
Eliminations for intersegment	**(3,131)**	(4,741)	(30,853)
Total operating expenses	**59,854**	47,469	62,048
Other Income and Deductions			
Regulated	**48**	17	31
Non-regulated	**--**	--	--
Total other income and deductions	**48**	17	31
Interest Charges			
Regulated	**4,624**	4,768	5,191
Non-regulated	**11**	25	42
Eliminations for intersegment	**--**	(11)	(116)
Total interest charges	**4,635**	4,782	5,117

	2003	2002	2001
Net Income			
Regulated	**2,348**	2,621	2,817
Non-regulated	**1,503**	1,016	819
Total net income	**3,851**	3,637	3,636
Assets			
Regulated	**130,224**	124,432	120,710
Non-regulated	**2,350**	2,055	3,469
Total assets	**132,574**	126,487	124,179
Capital Expenditures			
Regulated	**9,195**	9,415	7,070
Non-regulated	--	7	--
Total capital expenditures	**9,195**	9,422	7,070

(14) 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	Net Income (Loss)	Basic and Diluted Earnings(Loss) per Common Share(a)
Fiscal 2003				
September 30	$ 7,153,282	$ 231,609	$ (991,247)(b)	$ (.39)
December 31	15,501,819	1,850,943	692,765	.27
March 31	31,217,192	5,478,145	4,258,292	1.66
June 30	14,507,970	965,669	(109,203)	(.08)
Fiscal 2002				
September 30	$ 7,258,892	$ 479,305	$ (778,325)	$ (.31)
December 31	12,580,389	1,880,382	591,751	.24
March 31	25,158,025	4,843,984	3,745,226	1.49
June 30	10,872,913	1,197,781	78,061	.03

(a) Quarterly earnings per share may not equal annual earnings per share due to changes in shares outstanding.

(b) Net income (loss) for September 30, 2002 includes a cumulative effect of an accounting change. See Note 2 of the Notes to Consolidated Financial Statements in reference to the adoption of Financial Accounting Standards No. 143, entitled Accounting for Asset Retirement Obligations.

DELTA NATURAL GAS COMPANY, INC. AND SUBSIDIARY COMPANIES
VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED JUNE 30, 2003, 2002 AND 2001

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, 2003	$ 165,000	$ 536,910	$ 63,351	$ 415,261	$ 350,000
June 30, 2002	575,000	153,074	63,832	626,906	165,000
June 30, 2001	144,380	810,432	40,565	420,377	575,000

GAS SALES AGREEMENT

BY AND BETWEEN

DELTA NATURAL GAS COMPANY, INC.

AS BUYER

AND

WOODWARD MARKETING, L.L.C.

AS SELLER

GAS SALES AGREEMENT

THIS GAS SALES AGREEMENT made and entered into to be effective the 1st day of May, 2003, by and between the DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Buyer", and WOODWARD MARKETING, L.L.C., a Delaware corporation, hereinafter referred to as "Seller".

WITNESSETH THAT:

WHEREAS, Buyer and Seller have entered into a Gas Sales Agreement ("Agreement"), to be effective May 1, 2003, providing for the purchase by the Buyer and sale by Seller on a firm basis of 100% of the natural gas requirements of Buyer's residential and small commercial customers in specified service areas and providing for certain other services of Seller to Buyer, and

WHEREAS, Buyer is a party to FTS-1 Service Agreements with Columbia Gulf Transmission Company ("Columbia Gulf") and is a party to GTS Service Agreements with Columbia Gas Transmission Corporation ("Columbia") by which Buyer holds firm pipeline transportation and/or storage capacity on these two interstate pipelines, and

WHEREAS, during the term of this Agreement, Buyer desires to assign to Seller its pipeline and storage capacities under the Columbia Gulf and Columbia Service Agreements, and

WHEREAS, for the purpose of setting forth the terms of said agreements between Buyer and Seller, the parties have entered into this Agreement.

NOW, THEREFORE, for and in consideration of the covenants and agreements set forth herein, the parties agree as follows:

ARTICLE I
DEFINITIONS

Unless expressly stated otherwise, the following terms as used in this Agreement shall mean:

1.1 The term "Btu" shall mean British Thermal Unit (s) which shall mean that amount of heat energy required to raise the temperature of one avoirdupois pound of water from fifty-nine-degrees Fahrenheit (59 F) to sixty-degrees Fahrenheit (60 F) at standard atmospheric pressure, as determined on a dry basis. All prices and charges paid hereunder shall be computed on a "dry" Btu basis.

1.2 The term "day" shall mean the period of time beginning at 9:00 a.m., Central Time Zone, on a calendar day and ending at 9:00 a.m., Central Time Zone, on the following calendar day, or such other definition of day, as may change from time to time, set forth in Columbia's tariff on file with the Federal Energy Regulatory Commission, or any successor agency.

1.3 The term "Delivery Point(s)" is defined in Article IV.

1.4 The term "gas" shall include casinghead gas, natural gas from gas wells, and residue gas resulting from processing casinghead gas and gas well gas.

1.5 The term "Liquefiable Hydrocarbons" means all hydrocarbons (except those hydrocarbons separated from the gas stream by conventional single-stage mechanical field separation methods) or any mixture thereof that may be extracted from the gas sold hereunder other than methane (except for the nominal quantities lost during such processing operations) including, but not limited to, natural gasolines, butane's, propane and ethane.

1.6 The term "Liquid Hydrocarbons" means any hydrocarbons which, in their natural state, are liquids and which shall include any Liquefiable Hydrocarbons that condense out of the gas stream during production or transportation.

1.7 The term "Mcf" shall mean one thousand (1,000) cubic feet at a pressure of fourteen and seventy-three-hundredths (14.73) pounds per square inch absolute and at a temperature of sixty degrees (60 F) Fahrenheit, with correction from Boyle's Law.

1.8 The term "MMBtu" shall mean one million (1,000,000) Btu's.

1.9 The term "month" shall mean the period of time beginning on the first calendar day of each calendar month and ending on the first day of the following calendar month.

1.10 The term "year" shall mean a period of twelve (12) consecutive months, commencing on the first day of the month following the Effective Date, as defined in Article VI, and each subsequent twelve (12) month period; provided that the first year will include the period from the Effective Date until the first day of the following month if the Effective Date is not on the first day of a month.

ARTICLE II
QUANTITY AND NOMINATIONS

2.1 Purchase Quantity - Subject to the terms and conditions of this Agreement, Buyer shall purchase and receive and Seller shall sell and deliver on a firm basis a quantity of gas equal to 100% of Buyer's Columbia-supplied residential and small commercial supply requirements in the Delta-Stanton and Delta-Winchester service areas, and up to 100,000 Dth annually in the Delta-Cumberland service areas, subject to section 2.2. Seller expressly acknowledges that a large percentage of the industrial/large commercial end users on Buyer's systems do not purchase gas from Buyer and arrange for their own gas supplies. Volumes flowing at the Delivery Point(s) for these end users shall be the first gas through Columbia's meters, and Buyer's acceptance of these volumes on behalf of the end user(s) shall not constitute a violation of Seller's exclusive supplier provisions under this Agreement.

2.2 Maximum Quantity - Notwithstanding anything to the contrary herein, the maximum quantity of gas that Seller is obligated to sell and deliver at the Delivery Point(s) under this Agreement (herein referred to as the "MDQ") shall be equal to the lesser of (a) the GTS daily limitations as set forth in Columbia's FERC tariff and as indicated in Exhibit A or (b) the maximum amount of gas that can be transported on Columbia and redelivered at the Delivery Point(s) under the firm transportation contracts with Columbia and with Columbia Gulf Transmission Company ("Columbia Gulf") that are released or assigned to Seller in accordance with Article V below (herein referred to as the "Firm Transportation Contracts"). Upon the mutual agreement of the Parties, Seller may sell and Buyer may purchase quantities in excess of the MDQ. The price and terms of such excess sales will be mutually agreed upon by the Parties prior to the delivery of such excess gas.

2.3 Remedies for Failure to Deliver and Receive

2.3.1 Seller's Failure to Deliver

(a) If Seller fails to deliver to Buyer its natural gas requirements up to the MDQ on any day, for reasons other than (i) imbalances or variations under transportation agreements or operational balancing agreements, which are governed by Article V or (ii) an event of force majeure or an event described in Section 5.5, then Seller shall reimburse or credit to Buyer for the following:

(1) Seller will reimburse Buyer for the sum of (a) the difference, if positive, between (i) the price Buyer pays for a substitute supply of gas or other alternative fuel such as propane and (ii) the prices set forth in Section 3.1.1 of this Agreement (calculated based upon Buyer's actual load factor under this Agreement) multiplied by the quantity Seller failed to deliver in accordance with this subsection, (b) any reasonable incremental costs and expenses incurred in transporting the substitute supplies and (c) any reasonable incidental expenses incurred in purchasing the substitute supplies. Buyer agrees to act in good faith in purchasing such substitute supplies so as to minimize Seller's obligations to Buyer hereunder; or

(2) If Buyer, through reasonable efforts, is unable to obtain substitute supplies, then Seller shall provide Buyer the difference between the highest commodity price that was paid by Buyer for the purchase of gas or an alternative fuel, such as propane, during the last two years (not to exceed $10 per MMBtu) and the prices set forth in Section 3.1.1 of this Agreement (calculated based upon Buyer's actual load factor under this Agreement) multiplied by the quantity of gas Seller failed to deliver in accordance with the above.

2.3.2 Curtailment - In addition to the remedies set forth in Section 2.3.1, if for any reason, including an event of force majeure, Seller is unable to meet all of its firm sales obligations with Seller's available supplies on Columbia, then Seller will curtail its deliveries to all of its sales customers on a pro-rata basis based upon the actual nominations of Seller's other firm sales customers made during the period of curtailment and the actual nomination of Buyer not to exceed the MDQ to the extent that the curtailment of Seller's other customers would be useful in maintaining deliveries to Buyer. Upon Buyer's request, Seller will provide Buyer information to verify that deliveries to Buyer were curtailed in accordance with this subsection.

2.3.3 Failure to Take - If Buyer fails to receive and purchase its full requirements in accordance with Section 2.1 above, then Buyer will pay Seller $0.035 per MMBtu times the difference between (a) its full requirements and (b) the quantities actually taken by Buyer during the applicable seasonal period.

2.3.4 Exclusive Remedy - The Parties agree that the actual losses incurred by Buyer as a result of Seller's failure to deliver quantities and incurred by Seller as a result of Buyer's failure to take quantities would be uncertain and impossible to determine with precision. As a result, the payments by Seller and Buyer in accordance with Subsections 2.3.1 and 2.3.3, respectively, and the deliveries by Seller in accordance with Subsection 2.3.2 above shall be the sole and exclusive remedy, for Seller's failure to deliver or Buyer's failure to take the quantities set forth in this Article. The payments by Seller and Buyer pursuant to this Section 2.3 are reasonable compensation for such failures.

2.4 Uniform Takes - Unless permitted otherwise by Columbia, Buyer will receive gas at the Delivery Point(s), as defined in Section 4.1, at rates that are in compliance with the terms of the Firm Transportation Contract with Columbia that is released or assigned to Seller in accordance with Article V.

2.5 Alternate Rate Schedule – Prior to Seller submitting monthly nominations to Columbia hereunder, Buyer may direct Seller to cause gas sold hereunder to be delivered under Columbia Gas' Rate Schedule ITS. Notwithstanding the foregoing, Seller shall have the authority to determine whether sufficient ITS capacity exists to permit delivery of daily nominated quantities. In the event Seller reasonably determines that sufficient ITS capacity is not available to permit delivery of nominated quantities, Seller is authorized to cause Buyer's gas to be delivered under Columbia Gas' Rate Schedule GTS. Volumes delivered to Buyer on Columbia Gas under an Alternate Rate Schedule shall be assessed a transportation charge to Buyer of $0.25 / MMBtu, plus applicable fuel and surcharges.

ARTICLE III
PRICE

3.1 Commodity Price for All Other Quantities Within MDQ

3.1.1 City-gate Service - The price for each MMBtu of gas sold and delivered hereunder at the Delivery Point(s) up to the MDQ shall be priced at the Columbia Gulf Mainline monthly index as published in *Inside F.E.R.C's Gas Market* report minus $0.07/MMBtu plus applicable IT-S2 transportation and fuel charges. The pricing under this contract shall be redetermined in the event that Buyer's storage rights under the Columbia contracts are altered.

3.1.2 Fixed Price Alternative - In substitution for the Commodity Price, the Parties may mutually agree, through the utilization of the NYMEX natural gas futures or otherwise, to lock in a fixed price for all or part of the MDQ for one or more months. If the Parties agree to such a fixed price, then Buyer will be required to purchase the designated monthly quantities for which the Parties have agreed to a fixed price, notwithstanding any other provision to the contrary in this Agreement.

3.2 Commodity Price for Excess Gas - The price for each MMBtu of gas sold and delivered hereunder in excess of the MDQ shall be determined in accordance with Section 2.2 of this Agreement.

3.3 Transportation and Storage Costs – Buyer shall be responsible for paying Columbia Gulf and Columbia for transportation services rendered under the Firm Transportation Agreements. Seller shall be responsible for any charges incurred in connection with its utilization of capacity under Buyer's Firm Transportation Contracts for purposes other than providing gas supply to Buyer. Seller shall credit Buyer 90% of revenue derived from third-party release of Buyer's Firm capacity as posted on Transporter's Electronic Bulletin Board.

ARTICLE IV
DELIVERY POINTS

4.1 Delivery Points - The Delivery Points for all gas sold and delivered hereunder shall be at the points specified in Exhibit A hereto.

4.2 Adjustments to Delivery Points - It is recognized by both Parties that Seller's ability to deliver gas at the Delivery Point(s) set forth in Section 4.1 above is dependent upon Seller's ability to utilize the Firm Transportation Contracts released by Buyer to Seller in accordance with Article V below. These provisions are based on Columbia's tariff provisions in effect on the date of execution of this Agreement and Seller's ability to utilize such released, assigned or delegated contracts to deliver the gas sold hereunder at the Delivery Point(s) set forth in Section 4.1 above. The terms of this section shall be revised to reflect any substantial change in Columbia's tariff with regard to the utilization of such contracts and delivery point flexibility, so as to place both Parties in a relative position under this Agreement not substantially different from the position the Parties had prior to the change in such tariffs.

ARTICLE V
TRANSPORTATION AND STORAGE ARRANGEMENTS

5.1 Transportation and Storage Arrangements

5.1.1 Transfer of Arrangements - Buyer has firm transportation rights on Columbia Gulf and firm transportation and storage rights on Columbia as specified in Exhibit A hereto. It is recognized by both parties that Buyer holds firm transportation capacity on Columbia Gulf Transmission Company's pipeline under FTS-1 service agreements and firm transportation/storage capacity on Columbia under its GTS service agreements. In order to provide a delivered storage service to Buyer at the Delivery Point(s), on the Effective Date of this Agreement, Buyer will execute a Blanket Authorization Agreement between Seller and Columbia. Seller shall have full and complete control over the utilization of such contracts, including without limitation the manner and timing of any transportation, injections, and withdrawals of gas under such contracts; provided that Seller may not, without Buyer's prior written consent, amend the primary delivery points under the Firm Transportation Contracts or change the rate schedule or the level of maximum entitlement's under which such services are offered. Seller agrees not to amend or modify Buyer's agreements with the transporting pipelines listed in such Blanket Authorization Agreement in a manner which diminishes Buyer's rights and/or level of service therein, without Buyer's prior written consent. Buyer will also appoint Seller as its agent for purposes of administering the Firm Transportation Contracts for the transportation and storage of (a) any substitute gas supplies that Buyer purchases in accordance with Section 2.3.1 or (b) to the extent the release or assignments provided for above are not permitted by the pipelines' tariffs. Such release/assignment and agency arrangements shall be in accordance with the pipelines' tariffs and shall terminate upon the expiration of this Agreement. If, prior to the release or delegation of such rights, elections for receipt points, delivery points, supply leg capacity, monthly maximum daily quantity elections or any other similar elections must be given to Columbia then Buyer will cooperate with Seller to make such necessary elections as designated by Seller. Similarly, Buyer will cooperate with Seller to make any amendments to the contracts requested by Seller to become effective on the Effective

Date of this Agreement to the extent said amendments do not adversely affect, in Buyer's sole opinion, Buyer's costs or Buyer's level or quality of service. In the event of any supplementation or contradiction between the Blanket Authorization Agreement and this Agreement, the terms of this Agreement shall control and govern the rights, obligations, and liabilities of Seller and Buyer.

5.2 Responsibility for Firm Transportation and Storage Contracts

5.2.1 Responsibility for Administration – Subject to Buyer's obligation to pay Seller in accordance with Section 3.3 above, upon the transfer of the Firm Transportation Contracts, Seller shall assume all obligations and rights under such contracts, including without limitation, the obligation to submit nominations to Columbia, to pay any applicable scheduling or imbalance charges, or to provide fuel and loss quantities.

5.2.2 Operational Balancing Agreements – Seller will be responsible for correcting any imbalances or variations under the Firm Transportation. It is understood that Seller shall correct such imbalances or variations, pursuant to Rate Schedule GTS, through automatic storage injections and withdrawals. In addition, Buyer agrees to appoint Seller as its agent to enter into and maintain an Operational Balancing Agreement (OBA) with Columbia in accordance with Columbia's tariff. If Seller is unable to correct such imbalances or variations through automatic injections and withdrawals as set forth above due to inventory levels in storage for Buyer's account or otherwise, then any variance between actual deliveries and confirmed nominations at the Delivery Point(s) will be allocated to the OBA. Seller shall be responsible for correcting any such variation or imbalance under the OBA and any resulting month-end cashout.

5.2.3 Penalty Responsibility - Buyer will be required to reimburse Seller for (1) unauthorized overrun penalties associated with takes in excess of the maximum daily quantities under the Firm Transportation and Storage Contracts, (2) any penalties or charges that are imposed by Transporter(s) due to Buyer's failure to comply with a directive of the pipeline limiting quantities to less than Buyers contracted maximum daily quantities. (3) any daily variance charges or penalties imposed by Transporter(s). Other pipeline imbalances and related charges and/or penalties resulting from failure to take or dispatch agreed upon volumes shall be the responsibility of the party whose failure caused the imbalance or penalty.

5.3 Telemetry - Buyer shall authorize Seller to access Columbia telemetry readings on Buyer's behalf, so long as Buyer is not required to give up its current access to Columbia's telemetry readings.

5.3.1 Projected Requirements - Buyer shall provide Seller monthly projected requirements by the 23rd of the preceding month. Buyer will cooperate with Seller to ensure that nominations (including any necessary adjustments thereto) are made timely to Columbia and that such nominations reflect the actual expected deliveries and receipts. During the storage withdrawal season each year, if the cumulative variances between Buyer's projected monthly requirements and actual monthly takes exceed the cumulative Maximum Storage Quantities set forth under the heading "Capacity" in Exhibit A hereto, then the excess quantities shall be priced at the applicable *Gas Daily* midpoint price.

5.3.2 Forecasts and Nominations - Based on Buyer's projections set forth in Section 5.3.1, historical data and weather forecasting by Seller, Seller will forecast Buyer's daily natural gas requirements. Based on such forecast, Seller will submit the necessary nominations to Columbia in accordance with Section 5.2.1.

5.4 Adjustments to Imbalance Provisions - The purpose of Sections 5.1 through 5.3 is to establish the Parties' responsibilities for administering the firm contracts and the OBA released/assigned and delegated above, and for correcting any imbalances between receipts and deliveries or variations between confirmed nominations and actual deliveries at the Delivery Point(s). These provisions are based on (a) tariff provisions approved in Columbia's FERC Tariff on the date this Agreement was executed, including the right to balance any variation between projected and actual daily loads through injections and withdrawals from storage under the Firm Storage Contracts, and (b) the existing load profile of Buyer. The terms of this section shall be revised to reflect any substantial change in either (a) Columbia's tariff with regard to the correction of such imbalances or variations and any associated penalties or (b) Buyer's load profile, so as to place both Parties in a relative position under this Agreement not substantially different from the position the Parties had prior to the change in Columbia's tariff or Buyer's load profile. If the Parties are unable to agree on the appropriate revisions, the matter shall be submitted to arbitration in accordance with Article XIV, such decision to be effective on the first day of the month following the issuance of the arbitrator's decision.

5.5 Transportation Limitation - If either Columbia or Columbia Gulf interrupts, curtails or otherwise fails to receive, transport or deliver the gas sold and/or delivered hereunder and such interruption or curtailment is not due to Seller's failure to pay such transporters (unless to the extent Seller's failure to pay is the result of buyer's failure to reimburse Seller in accordance with Section 3.3 above), then Seller's obligation to deliver gas under this Agreement shall be suspended for that portion of the quantities interrupted or curtailed by such transporters for so long as such interruption or curtailment of deliveries continues. This Article 5.5 shall apply only when Seller is transporting gas on Columbia under Buyer's GTS contracts.

5.6 Displacement Transportation - Seller acknowledges that, under separate agreements, Buyer transports gas to Columbia on behalf of third parties. To address differences between scheduled deliveries and actual deliveries, Buyer and Columbia have agreed that any underdeliveries of third party transportation gas scheduled to be delivered by Buyer to Columbia will be made up by Buyer through GTS storage withdrawals. Any overdeliveries by Buyer under the third party transportation agreements will result in injections of the excess volumes into the Delta-Cumberland GTS storage account. At the close of each month, withdrawals and injections due to daily transportation underdeliveries and overdeliveries will be balanced against each other. If the result is a net withdrawal, Buyer will purchase this volume of gas from Seller in addition to purchases at other points of delivery. If the result is a net injection, Buyer will credit that volume against other volumes purchased from Seller during that month.

ARTICLE VI
TERM OF AGREEMENT

6.1 Primary Term - This Agreement shall become effective on May 1, 2003 (herein referred to as the "Effective Date") and shall continue in full force and effect for a primary term of three years through April 30, 2006. At the expiration of the primary term, this Agreement will be extended for additional one-year periods, unless on or before 60 days prior to the expiration of the primary term, either Party gives written notice to the other Party that it does not desire to extend the primary term.

6.2 Transfer of Gas in Storage - Any gas remaining in storage at the termination of this Agreement that was injected on or before March 31 of the year in which the Agreement terminates shall be transferred and sold by Seller to Buyer at the arithmetic average of the Commodity Prices that were applicable during the months of November, December, January, February and March that immediately preceded the termination date of this Agreement. Any gas remaining in storage at the termination of this Agreement that was injected after March 31 of the year in which the Agreement terminates shall be transferred and sold by Seller to Buyer at a price mutually agreed to by the Parties; provided that Seller will not inject gas into storage for Buyer's account after March 31 of such year, unless Buyer consents to such injections. For purposes of determining the quantities injected between March 31 and the termination of this Agreement, the quantities injected into storage on or before March 31 shall be deemed withdrawn first, prior to the quantities injected after March 31 of such year.

ARTICLE VII
TITLE AND TAXES

7.1 Transfer of Title, Possession and Control - Title to the gas sold hereunder shall pass from Seller to Buyer upon delivery of said gas to Buyer at the applicable Delivery Point(s). As between the Parties hereto, Seller shall be deemed to be in control and possession of all gas delivered hereunder and shall indemnify and hold Buyer harmless from any damage, injury or losses which occur prior to delivery to Buyer at the Delivery Point(s); otherwise, Buyer shall be deemed to be in exclusive control and possession thereof and shall indemnify and hold Seller harmless from any other injury, damage or losses.

7.2 Warranty of Title - Except as set forth below, Seller warrants title to all gas delivered hereunder by Seller or that Seller has the right to sell the same, and that such gas is free from liens and adverse claims of every kind. Seller will indemnify and save Buyer harmless against all loss, damage and expense of every character on account of adverse claims which are applicable to the gas before the title to the gas passes to

Buyer. Buyer will indemnify and save Seller harmless against all loss, damage and expense of every character on account of adverse claims which are applicable to the gas after title passes to Buyer.

7.3 Taxes - Buyer shall reimburse Seller for any taxes, fees or charges, other than income taxes, which are levied by a governmental or regulatory body on the gas sold under this Agreement, and gas held in Buyer's storage accounts.

ARTICLE VIII
QUALITY AND PRESSURE

8.1 Quality and Pressure Requirements - Seller will deliver the gas sold under this Agreement at the receipt points under the Firm Transportation Contracts with Columbia under conditions that meet the quality and pressure specifications set forth in Columbia's tariff. Neither Seller nor Buyer shall be obligated to install or operate compression facilities.

8.2 Remedy for Noncompliance - If (a) the gas sold under this Agreement fails to meet the standards concerning quality or pressure set forth in Section 8.1, (b) Columbia fails to receive and transport the gas and (c) Columbia does not deliver the requirements of Buyer, then Seller shall be deemed to have failed to deliver the quantities nominated by Buyer, and shall be subject to the remedies set forth in Section 2.3 above.

ARTICLE IX
MEASUREMENT AND TESTS

9.1 Measurement Point - The natural gas sold hereunder shall be measured at or near the Delivery Point(s) on Columbia's system at pressures in existence from time to time and shall be corrected to the unit of measurement, which shall be one MMBtu.

9.2 Standards for Measurement and Tests - Unless specified herein to the contrary, the standards for measurement and tests shall be governed by those standards set forth in Columbia's tariff.

9.3 Operation of Measurement - Seller, as the replacement shipper under the Firm Transportation Contracts, shall cause Columbia to operate the measurement facilities involved in metering and receiving gas at the *Delivery* Point(s). This operation shall include the changing of all charts, calculation of volumes and the calibration, maintenance, adjustments and the repair of such meter facilities in accordance with Columbia's tariff. To the extent either Party has access rights to the Delivery Point(s), including the measurement facilities, that Party will provide similar access to the other Party, to the extent permitted, to fulfill any rights or obligations under this Agreement.

ARTICLE X
PROCESSING

Seller may process the gas to remove any Liquid Hydrocarbons or Liquefiable Hydrocarbons prior to the delivery of the gas to Buyer at the Delivery Point(s). In the event Seller elects to process the gas, any hydrocarbons so removed shall be Seller's sole responsibility and all costs (including associated transportation costs) shall be paid by Seller and Seller shall indemnify, defend and hold Buyer harmless therefrom.

ARTICLE XI
BILLING AND PAYMENT

11.1 Billing and Payment - Seller shall render to Buyer, at the address indicated in Section 15.5 hereof, on or before the fifteenth (15th) day of each calendar month by certified, registered or overnight mail an invoice for all gas purchased during the preceding month according to the measurements, computations, and prices provided herein. Buyer agrees to make payment hereunder to Seller for its account in available funds by wire transfer or by mail at such location as Seller may from time to time designate in writing. Payment shall be made by Buyer within the later of (a) the twenty-fifth (25th) of the month or (b) ten (10) days of the date of receipt of Seller's invoice; provided that if Columbia's billing schedule changes in either of their tariffs, then Buyer will pay Seller on an earlier date to coincide with the earlier of when payments are due to Columbia under the Firm Transportation Contracts. If the invoiced amount is not paid when due, then interest on any unpaid amount shall accrue at the then current prime rate of interest *as published under "Money Rates" by the Wall Street Journal*, not to exceed any applicable maximum lawful rate together with any court costs, attorney's fees and all other costs of collection which Seller may incur in enforcing the terms of this Agreement. If such default continues for thirty (30) days after written notice from Seller to Buyer, Seller may suspend gas deliveries hereunder without liability and without prejudice to other remedies. Notwithstanding the above, if a good faith dispute arises between the Parties over the amounts due under the invoice for any matters, then Buyer will pay that portion of the statement not in dispute on or before the due date and both Parties will continue to perform their obligations under this Agreement during such dispute; provided that Buyer will be required to provide, within 30 days of a written request by Seller, a good and sufficient surety bond guaranteeing payment to Seller of the amount ultimately found due.

11.2 Credit Standards - All sales hereunder during the term of this Agreement shall be subject to appropriate review and approval by Seller's Credit Department. Buyer agrees to provide information as reasonably required to Seller's Credit Department to effect a proper evaluation. Without limiting the above, Seller may suspend deliveries under this Agreement if Buyer (a) admits that it is unable to pay its debts as they become due, (b) applies for or agrees to the appointment of a receiver or trustee in liquidation of it or its properties, (c) makes a general assignment for the benefit of creditors, (d) files a voluntary petition in bankruptcy or a petition seeking reorganization or an arrangement with creditors under any bankruptcy law, (e) is a Party against whom a petition under any bankruptcy law is filed and such Party admits the material allegations in such petition filed against it, (f) is adjudicated as bankrupt under a bankruptcy law or (g) fails to meet the credit standards set forth in Columbia's tariff.

11.3 Adjustments to Payments - If any overcharge or undercharge in any form whatsoever shall at any time be found and the bill therefor has been paid, Seller shall refund the amount of any overcharge received by Seller and Buyer shall pay the amount of any undercharge, within thirty (30) days after final determination thereof; provided, there shall be no retroactive adjustment of any overcharge or undercharge if the matter is not brought to the attention of the other Party in writing within the lesser of (a) twelve (12) months following the date deliveries under this Agreement were made or (b) the period in which the statements and payments to Columbia become final.

11.4 Review of Books and Records - Buyer and Seller shall have the right to inspect and examine, at reasonable hours, the books, records and charts of the other (pertaining to the sale of gas hereunder or any other charge or fee arising hereunder), the confidentiality of which they agree to maintain, to the extent necessary to verify the accuracy of any invoice, charge or computation made pursuant to this Agreement.

ARTICLE XII
REGULATORY BODIES

12.1 Laws and Regulations - This Agreement shall be subject to all valid applicable governmental laws and orders, regulatory authorizations, directives, rules and regulations of any governmental body or official having jurisdiction over the Parties, their facilities, the gas or this Agreement or any provision thereof; but nothing contained herein shall be construed as a waiver of any right to question or contest any such law, order, rule or regulation in any forum having jurisdiction.

12.2 Reliance on Law - The Parties are entitled to act in accordance with a law until such law is amended, reversed or otherwise disposed in a final nonappealable order.

12.3 Cooperation - The Parties shall cooperate to ensure compliance with all governmental regulation, including obtaining and maintaining all necessary regulatory authorizations or any reasonable exchange or provision of information needed for filing or reporting requirements.

12.4 Changes in Law or Regulation - If any federal or state statute or regulation or order by a court of law or regulatory authority directly or indirectly (a) prohibits performance under this Agreement, (b) makes such performance illegal or impossible or (c) effects a change in a substantive provision of this Agreement which has a significant material adverse impact upon the ability of either Party to perform its obligations under this Agreement, then the Parties will use all reasonable efforts to revise the Agreement so that (a) performance under the Agreement is no longer prohibited, illegal, impossible or is no longer impacted in a material adverse fashion, and (b) the Agreement is revised in a manner that preserves, to the maximum extent possible, the respective positions of the Parties. Each Party will provide reasonable and prompt notice to the other Party as to any proposed law, regulations or any regulatory proceedings or actions that could affect the rights and obligations of the Parties. If the Parties are unable to revise the Agreement in accordance with the above, then the Party whose performance is rendered prohibited, illegal, impossible or is impacted in a material adverse manner shall have the right, at its sole discretion, to suspend or terminate this Agreement upon written notice to the other Party.

ARTICLE XIII
FORCE MAJEURE

13.1 Force Majeure - If Buyer or Seller is rendered unable, wholly or in part, by force majeure to perform obligations under this Agreement, other than the obligation to make payments due under this Agreement, it is agreed that the performance of the respective obligations of Seller and Buyer to deliver or purchase and receive gas, so far as they are affected by force majeure, shall be excused and suspended from the inception of any such inability until it is corrected, but for no longer period. Buyer or Seller, whichever is claiming such inability, shall give notice thereof to the other as soon as practicable after the occurrence of the force majeure. Such notice may be given orally or in writing, but, if given orally, it shall be promptly confirmed in writing, giving reasonably full particulars. Such inability shall be promptly corrected to the extent it may be corrected through the exercise of reasonable diligence by the other Party claiming inability by reason of force majeure.

13.2 Liability During Force Majeure - Neither Buyer nor Seller shall be liable to the other for any losses or damages, regardless of the nature thereof and however occurring, whether such losses or damages be direct or indirect, immediate or remote, by reason of, caused by, arising out of or in any way attributable to suspension of the performance of any obligation of either Party to the extent that such suspension occurs because a Party is rendered unable wholly or in part, by force majeure to perform its obligations, unless the force majeure event is caused by the negligence or willful misconduct of the Party claiming the force majeure.

13.3 Definition of Force Majeure - The term "force majeure" as used herein shall mean an event that (a) restricts or prevents performance under this Agreement, (b) is not reasonably within the control of the Party claiming suspension and (c) by the exercise of due diligence, such Party is unable to prevent, overcome or remedy. Events that may give rise to a claim of force majeure include acts of God, epidemics, landslides, hurricanes, floods, washouts, lightning, earthquakes, storm warnings, perils of the sea, acts of any court or governmental or regulatory authorities acts of civil disorder, acts of industrial disorder, accidents to Seller's, Buyer's or any transporters facilities or storage or pipeline system, freezing of Seller's or its suppliers' wells, lines of pipe, storage facilities or other equipment, necessities for making repairs or alterations to machinery, wells, platforms, lines of pipe, storage facilities, pumps, compressors, valves, gauges or any other similar equipment, cratering, blowout or failure of any well or wells to produce, or any similar event or cause; provided, however, the settlement of any labor dispute to prevent or end any act of industrial disorder shall be within the sole discretion of the Party to this Agreement involved in such labor dispute, and the above requirement that an inability shall be corrected with reasonable diligence shall not apply to labor disputes. Notwithstanding the above, it is expressly agreed that the failure of, or inability to make delivery from, any single source of supply shall not constitute an event of force majeure beyond the greater of (a) the period necessary for Seller to locate another supply of gas, not to exceed one day or (b) the period necessary to adjust the nominations on the applicable pipeline(s) to transport gas from another supply of gas.

13.4 Termination - If a force majeure event continues for a period of thirty (30) days, then the Party which did not claim such force majeure may at any time thereafter terminate this Agreement upon ten (10) days prior written notice to the extent the force majeure event has not been corrected prior to the expiration of such notice period.

ARTICLE XIV
ARBITRATION

14.1 Submission of Dispute for Arbitration - Any controversy pertaining to matters expressly made subject to arbitration under this Agreement shall be determined by a board of arbitration, consisting of three members, upon notice of submission given by either Party, which notice shall also name one (1) arbitrator. The Party receiving such notice, shall, by notice to the other Party within ten (10) days thereafter, name the second arbitrator, or failing to do so, the Party giving notice of submission shall name the second arbitrator. The two (2) arbitrators so appointed shall name a third arbitrator, or, failing to do so within ten (10) days, the third arbitrator shall be appointed by the person who is the senior (in terms of service) actively-sitting judge of the United States District Court for the District where Buyer's principal place of business is located.

14.2 Qualification of Arbitrators - The arbitrators shall be qualified by education, experience and training in the natural gas industry to decide upon the particular question in dispute.

14.3 Arbitration Proceedings - The arbitrators so appointed, after giving the Parties due notice of the date of a hearing and reasonable opportunity to be heard, shall promptly hear the controversy in the location where Buyer's principal place of business is located and shall thereafter render their decision determining said controversy no later than ninety (90) days after such board has been appointed. Any decision requires the support of a majority of the arbitrators. If the board of arbitration is unable to reach such decision, new arbitrators will be named and shall act hereunder, at the request of either Party, in a like manner as if none has been previously named. After the presentation of evidence has been concluded, each Party shall submit to the arbitrators a final offer of its proposed resolution of the dispute. The arbitrators shall approve the final offer of one Party, without modification and reject that of the other. In considering the evidence and deciding which final offer to approve, the arbitrators shall be guided by the criteria described in the applicable section of this Agreement.

14.4 Arbitrator's Decision - The decision of the arbitrators shall be rendered in writing and supported by written reasons. The decision of the arbitrators shall be final and binding upon the Parties. The decision of the arbitrator(s) shall be kept confidential in accordance with Section 15.1 of this Agreement. Each Party shall bear the expenses of its chosen arbitrator, and the expenses of the third arbitrator shall be borne equally by the Parties. Each Party shall bear the compensation and expenses of its legal counsel, witnesses and employees.

ARTICLE XV
MISCELLANEOUS

15.1 Confidentiality - Except as necessary to obtain the transportation of the gas under this Agreement, or as otherwise provided herein, Seller and Buyer agree to maintain the confidentiality of this Agreement and each of the terms and conditions hereof, and Seller and Buyer agree not to divulge same to any third party except to the extent, and only to the extent, required by law, court order or the order or regulation of an administrative agency having jurisdiction over Buyer or Seller or the subject matter of this Agreement. If required to be disclosed, then the Party subject to the disclosure requirement shall (a) notify the other Party immediately and (b) cooperate to the fullest extent in seeking whatever confidential status may be available to protect any material so disclosed.

15.2 No Incidental, Consequential or Punitive Damages - Except as expressly provided in this Agreement, the Parties hereto waive any and all rights, claims, or causes of action arising under this Agreement for incidental, consequential or punitive damages. Any damages resulting from a breach of this Agreement by either Party shall be limited to actual damages incurred by the Party claiming damages.

15.3 Third Party Beneficiaries - Neither Buyer nor Seller intend for the provisions of this Agreement to benefit any third party. No third party shall have any right to enforce the terms of this Agreement against Buyer or Seller.

15.4 Waiver of Default - No waiver by Buyer or Seller of any default of the other under this Agreement shall operate as a waiver of any future default, whether of a like or different character.

15.5 Notices - Except as otherwise expressly provided in this Agreement, every notice, request, statement and invoice provided in this Agreement shall be in writing directed to the Party to whom given, made or delivered at such Party's address as follows:

Buyer:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391
Attention: Mr. Brian Ramsey
Phone: 859-744-6171 Ext.158
Fax: 859-744-3623
Email: bramsey@deltagas.com

Seller:

Woodward Marketing, L.L.C
377 Riverside Drive, Suite 109
Franklin, TN 37064
Attention: Mr. Rob Ellis
Phone: 615-595-2878
Fax: 615-794-0947

Nominations:

Woodward Marketing, L.L.C.
11251 Northwest Freeway, Suite 400
Houston, TX 77092
Attention: Mr. Rick Sullivan
Phone: 713-688-7771
Fax: 713-688-5124

Either Buyer or Seller may choose one or more of its addresses for receiving invoices, statements, notices and payments by notifying the other in the manner as provided above. All written notices, requests, statements and invoices shall be considered transmitted at the time of delivery, if hand delivered, or, if delivered by mail, on the next working day after mailing; if transmitted by telephone or other oral means or by telecopy or other form of electronic or telegraphic communication, all such notices shall be considered transmitted at the time of oral communication or at the time the telecopy or other form of electronic or telegraphic communication was sent.

15.6 Choice of Law - The Parties agree that the laws of the Commonwealth of Kentucky shall control construction, interpretation, validity and/or enforcement of this Agreement.

15.7 Assignment - All provisions of this Agreement shall extend to and be binding on the successors and assigns of the Parties hereto insofar as applicable to the rights and obligations succeeded to or assigned, but no succession or assignment shall relieve the assigning or succeeded to Party of its obligations without written consent of the other Party, which consent shall not be unreasonably withheld; provided that either Party may assign this Agreement to an affiliate without the prior written consent of the other Party. Nothing in this section prevents either Party from pledging or mortgaging all or any part of such Party's property as security. Buyer shall require any purchaser or lessee of Buyer's distribution system to assume the obligations under this Agreement to the extent so elected by Seller.

15.8 Interpretation - In interpretation and construction of this Agreement, no presumption shall be made against any Party on grounds such Party drafted the Agreement or any provision thereof.

15.9 Headings - The headings of any article, section or subsection of this Agreement are for purposes of convenience only and shall not be interpreted as having meaning or effect.

15.10 Entire Agreement - The terms and conditions contained herein constitute the full and complete agreement between the Parties and any change to be made must be submitted in writing and agreed to by both Parties.

15.11 Severability - Except as otherwise stated herein, any article or section declared or rendered unlawful by a court of law or regulatory authority with jurisdiction over the Parties or deemed unlawful because of a statutory change will not otherwise affect the lawful obligations that arise under this Agreement.

15.12 Enforceability - Each Party represents that it has all necessary power and authority to enter into and perform its obligations under this Agreement and that this Agreement constitutes a legal, valid and binding obligation of that Party enforceable against it in accordance with its terms, except as such enforceability may be affected by any bankruptcy law or the application of principles of equity.

IN WITNESS WHEREOF, this Agreement is executed in multiple counterparts, each of which is an original as of July ___, 2003.

DELTA NATURAL GAS COMPANY, INC.	WOODWARD MARKETING, L.L.C.
By: ____________________	By: ________________________
Name: __________________	Name: ______________________
Title: ___________________	Title: _______________________

EXHIBIT A

BUYER: Delta Natural Gas Company, Inc.

Pursuant to the Gas Sales Agreement between Seller and Buyer, the Columbia Gulf Transmission Company's FTS-1 contracts and the Columbia Gas Transmission Company's GTS contracts are as follows:

All volumes in Dth

Columbia Gulf Transmission Pipeline Capacity:

	FTS-1	MDQ
Delta-Winchester Contract No.	43829	1682
Delta-Stanton Contract No.	43827	860
Delta-Cumberland Contract No.	43828	1836

Columbia Gas Transmission Pipeline Capacity:

	GTS	
Delta-Winchester Contract No.	37815	4950
Delta-Stanton Contract No.	37814	2530
Delta-Cumberland Contract No.	37813	5400

Columbia Gas Transmission Storage Capacity:

	CAPACITY
Delta-Winchester	162857
Delta-Stanton	83254
Delta-Cumberland	177662

Columbia Gas Transmission Delivery Points:

	Delivery Point	Meter No.
Delta-Winchester Contract No.	Kingston-Terrill	800809
	Frenchburg	803544
	Owingsville	803545
	Camargo	803563
	Sharpsburg	803564
	North Middletown	803512
	Mt. Olivet	804148
Delta-Stanton Contract No.	Stanton	800803
Delta-Cumberland Contract No.	Manchester	805992
	Beattyville	832867

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

	2003	2002	2001	2000	1999
Earnings					
Net income	**$ 3,850,607**	$ 3,636,713	$ 3,635,895	$ 3,464,858	$ 2,150,794
Provisions for income taxes	**2,413,357**	2,249,500	2,232,500	2,068,500	1,239,100
Fixed charges	**4,665,030**	4,806,457	5,140,965	4,777,031	4,557,936
Total	**$10,928,994**	$10,692,670	$11,009,360	$10,310,389	$ 7,947,830
Fixed Charges					
Interest on debt	**$ 4,441,037**	$ 4,620,597	$ 4,955,805	$ 4,593,571	$ 4,373,776
Amortization of debt expense	**193,993**	161,160	161,160	161,160	161,160
One third of rental expense	**30,000**	24,700	24,000	22,300	23,000
Total	**$ 4,665,030**	$ 4,806,457	$ 5,140,965	$ 4,777,031	$ 4,557,936
Ratio of earnings to fixed charges	**2.34x**	2.22x	2.14x	2.16x	1.74x

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.

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 333-104301 of Delta Natural Gas Company, Inc. on Form S-2 of our report dated August 15, 2003, related to the consolidated financial statements of Delta Natural Gas Company, Inc. as of and for the years ended June 30, 2003 and 2002, appearing in this Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2003.

DELOITTE & TOUCHE LLP

Cincinnati, Ohio
September 5, 2003

Exhibit 31.1

CERTIFICATIONS

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)) for the registrant and have:

   a. Designed such disclosure controls and procedures 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. Evaluated the effectiveness of the registrant's disclosure controlsand procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c. Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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.

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: September 5, 2003

By: /s/Glenn R. Jennings
Glenn R. Jennings
President & Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, John F. Hall, 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)) for the registrant and have:

   a. Designed such disclosure controls and procedures 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. Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c. Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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.

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: September 5, 2003

By: /s/John F. Hall
John F. Hall
Vice President – Finance, Secretary & Treasurer

Exhibit 32.1

Written Statement of the Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, I, the undersigned President and Chief Executive Officer of Delta Natural Gas Company, Inc. (the "Company), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the year ended June 30, 2003 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/Glenn R. Jennings
Glenn R. Jennings

September 5, 2003

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Delta Natural Gas Company, Inc. and will be retained by Delta Natural Gas Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Written Statement of the Principal Financial Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, I, the undersigned Vice President – Finance, Secretary & Treasurer of Delta Natural Gas Company, Inc. (the "Company), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the year ended June 30, 2003 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/John F. Hall
John F. Hall

September 5, 2003

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Delta Natural Gas Company, Inc. and will be retained by Delta Natural Gas Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

BOARD OF DIRECTORS

Donald R. Crowe (a)
Retired Senior Analyst
Department of Insurance
Commonwealth of Kentucky
Lexington, Kentucky

Jane H. Green (a)
Retired Vice President -
Human Resources and
Corporate Secretary

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

Billy Joe Hall (b)
Investment Broker
LPL Financial Services
(general brokerage services)
Mount Sterling, Kentucky

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

Michael J. Kistner (b)
Consultant
MJK Consulting
(financial consulting)
Pewee Valley, Kentucky

Lewis N. Melton (a)
Professional Engineer
Secretary
Vaughn & Melton, Inc.
(consulting engineering)
Middlesboro, Kentucky

Harrison D. Peet (c)
Chairman of the Board
Retired President
and Chief Executive Officer

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

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

(a) Member of Nominating and Compensation Committee (b) Member of Audit Committee
(c) Member of Executive Committee

Pictured above left to right seated: Billy Joe Hall, Harrison D. Peet, Jane H. Green, Michael J. Kistner
Standing left to right: Donald R. Crowe, Glenn R. Jennings, Arthur E. Walker, Jr., Lewis N. Melton, Lanny D. Greer, Michael R. Whitley

OFFICERS

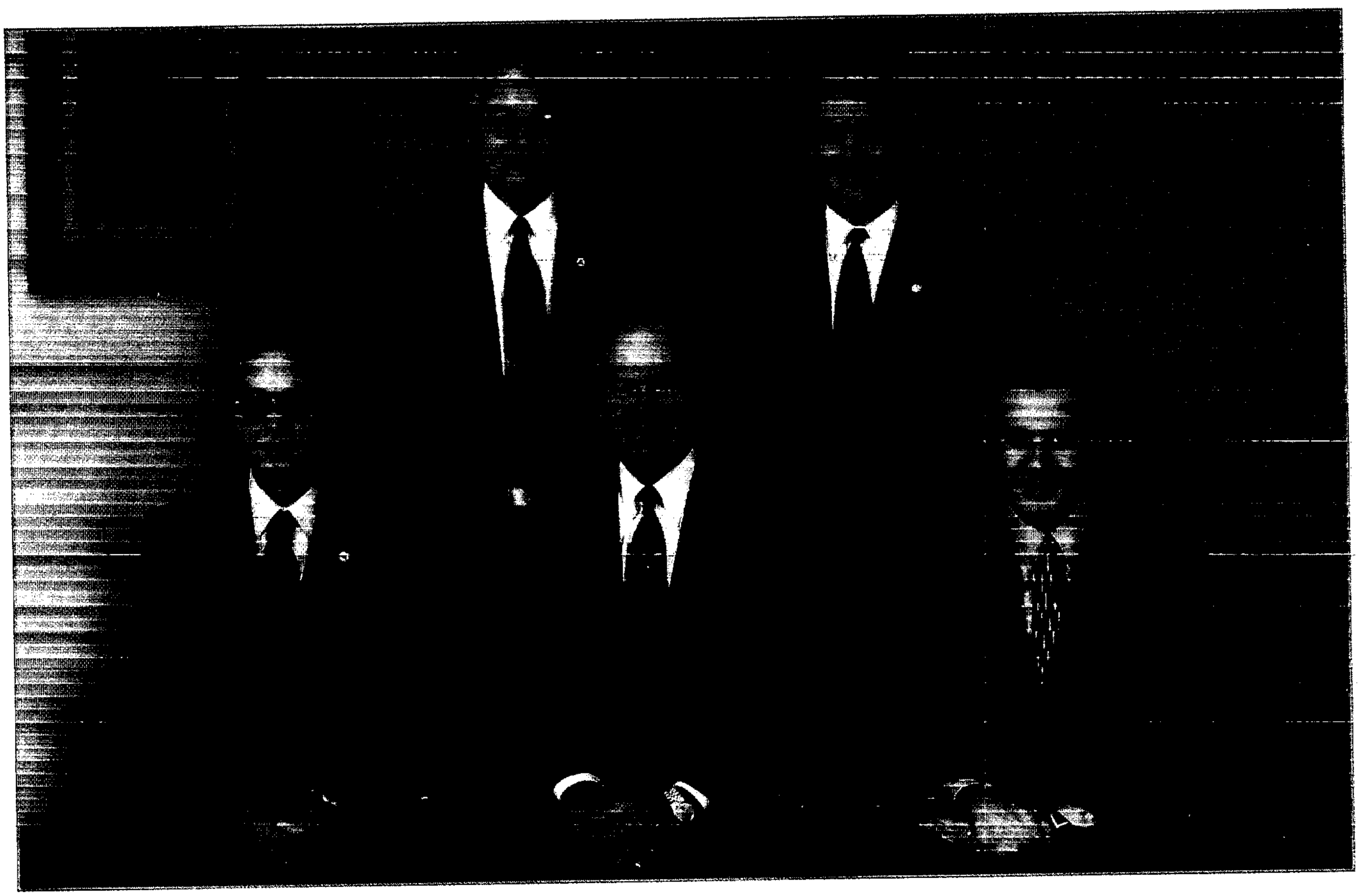
John B. Brown
Controller

Johnny L. Caudill
Vice President -
Administration and
Customer Service

John F. Hall
Vice President -
Finance, Secretary
and Treasurer

Alan L. Heath
Vice President -
Operations and
Engineering

Glenn R. Jennings
President and
Chief Executive Officer



Left to right seated: John F. Hall, Alan L. Heath, John B. Brown

Standing left to right: Johnny L. Caudill, Glenn R. Jennings

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, e-mail: ebennett@deltagas.com.

INDEPENDENT PUBLIC ACCOUNTANTS

Deloitte & Touche LLP
Suite 1900
250 East Fifth Street
Cincinnati, Ohio 45202

TRUSTEE AND INTEREST PAYING AGENTS FOR DEBENTURES
6 5/8% due 2023

Corporate Trust Bank One
235 W. Schrock Rd.
Westerville, Ohio 43081

7.15% due 2018; 7% due 2023

Fifth Third Bank
38 Fountain Square Plaza
Cincinnati, Ohio 45202

DISBURSEMENT AGENT, TRANSFER AGENT AND REGISTRAR FOR COMMON SHARES; DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN ADMINISTRATOR AND AGENT

Computershare Investor Services, LLC
2 North LaSalle Street
Chicago, Illinois 60602
1-888-294-8217

2003 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.

2003 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, 2003, 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, 2003.

SEC FORM 10-K

A copy of Delta's most recent annual report on SEC Form 10-K is available, without charge, upon written request to Emily P. Bennett, Director - Corporate Services, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391.

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.
AND SUBSIDIARY COMPANIES

3617 Lexington Road
Winchester, Kentucky 40391
Website: www.deltagas.com
Phone: 859.744.6171
Fax: 859.744.6552