UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended June 30, 2017

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

For the transition period from _______ to ________

Commission File No. 0-8788

DELTA NATURAL GAS COMPANY, INC.

(Exact name of registrant as specified in its charter)

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

859-744-6171

(Registrant's telephone number, including area code)

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

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

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

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided to Section 13(a) of the Exchange Act. ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recent completed second fiscal quarter. $208,936,596.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. As of August 31, 2017, Delta Natural Gas Company, Inc. had outstanding 7,135,373 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, 2017, is incorporated by reference in Part III of this Report.

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PART I

Item 1. Business

References to "Delta", "the Company", "we", "us" and "our" refer to Delta Natural Gas Company, Inc. and its consolidated subsidiaries, except as otherwise stated. We were incorporated under the laws of the Commonwealth of Kentucky on October 7, 1949. Unless otherwise stated, "2017", "2016" and "2015" refers to the respective twelve month periods ending June 30. Delta's NASDAQ symbol is DGAS.

General

Delta distributes or transports natural gas to approximately 36,000 customers. Our distribution and transmission systems are located in central and southeastern Kentucky, and we own and operate an underground natural gas storage field in southeastern Kentucky. We transport natural gas to industrial customers who purchase their natural gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system and extract liquids from natural gas in our storage field and on our pipeline systems that are sold at market prices. We have three wholly-owned subsidiaries. Delta Resources, Inc. ("Delta Resources") buys natural gas and resells it to industrial or large-volume customers on Delta's system. Delgasco, Inc. ("Delgasco") buys natural gas and resells it to Delta Resources and to customers not on Delta's system. Enpro, Inc. ("Enpro") owns and operates natural gas production properties and undeveloped acreage.

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, transporting, producing and processing natural gas in our service territory.

We strive to achieve operational excellence through economical, reliable service with an emphasis on responsiveness to customers. We continue to invest in facilities for the distribution, transportation 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, we will continue a conservative strategy of managing market risk arising from fluctuations in the prices of natural gas and natural gas liquids.

We operate through two segments, a regulated segment and a non-regulated segment.

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.

On February 20, 2017, we entered into an Agreement and Plan of Merger ("Merger Agreement") with PNG Companies, LLC ("PNG"), hereinafter referred to as the "Merger". For further information, see Note 18 of the Notes to Consolidated Financial Statements.

Regulated Operations

Distribution and Transportation

Through our regulated segment, we distribute natural gas to our retail customers in 23 predominantly rural counties. In addition, our regulated segment transports natural gas to large-volume customers on our system who purchase their natural gas in the open market. Our regulated segment also transports natural gas on behalf of local producers and other customers not on our distribution system.

The economy of our service area is based principally on coal mining, farming and light industry. The communities we serve typically contain populations of less than 20,000. Our three largest service areas are Nicholasville, Corbin and Berea, Kentucky. In Nicholasville we serve approximately 8,000 customers, in Corbin we serve approximately 6,000 customers and in Berea we serve approximately 4,000 customers. Some of the communities we serve continue to expand, resulting in growth opportunities for us. Industrial parks have been developed in our service areas, which could result in additional growth in industrial customers.

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. Their regulation of our business includes approving the rates we are permitted to charge our regulated customers. The impact of this regulation is further discussed in Note 14 of the Notes to Consolidated Financial Statements in Item 8 and under "Regulatory Matters" in Item 1.

Factors that affect our regulated revenues include the rates we charge our customers, economic conditions in our service areas, competition, the cost of natural gas and weather. Our current rate design lessens the impact weather has on our regulated revenues as our rates include both fixed customer charges and volumetric rates which include a weather normalization tariff that adjusts rates due to variations in weather. Market risk arising from fluctuations in the price of natural gas is mitigated through the natural gas cost recovery rate mechanism which permits us to pass through to our regulated customers changes in the price we must pay for our natural gas supply. However, increases in our rates may cause our customers to conserve or to use alternative energy sources.

Our regulated sales are seasonal and temperature sensitive since the majority of the natural gas we sell is used for heating. During 2017, 74% of the regulated volumes were sold during the heating season (December through April). Variations in the average temperature during the winter impact our volumes sold. Our weather normalization tariff permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

We compete with alternate sources of energy for our regulated distribution customers. These alternate sources include electricity, geo-thermal, coal, oil, propane, wood and solar.

Our large-volume regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers. Customers for whom we transport natural gas could by-pass our transportation system to directly connect to interstate pipelines or other transportation providers. Customers may undertake such a by-pass in order to seek lower prices for their natural gas transportation services. Our large-volume customers who are in close proximity to alternative supplies are likely to consider taking this action. Additionally, some of our industrial customers are able to switch to alternative sources of energy. These are competitive concerns that we continue to address by utilizing our non-regulated segment to offer these customers natural gas supply at competitive market-based rates.

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

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

Natural Gas Supply

We maintain an active natural gas supply management program that emphasizes long-term reliability and the pursuit of cost-effective sources of natural gas for our customers. We purchase our natural gas from a combination of interstate and Kentucky sources. Our distribution and transportation system interconnects with interstate pipelines owned by Columbia Gas Transmission Corporation ("Columbia Gas"), Columbia Gulf Transmission Corporation ("Columbia Gulf"), Tennessee Gas Pipeline ("Tennessee") and Texas Eastern Transmission Corporation ("Texas Eastern"). In our fiscal year ended June 30, 2017, we purchased approximately 99% of our natural gas from interstate sources.

Interstate Natural Gas Supply

Our regulated segment acquires its interstate natural gas supply from natural gas marketers. We currently have commodity requirements agreements with CenterPoint Energy Services, Inc. ("CenterPoint") (formerly Atmos Energy Marketing) for our Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied areas. Under these commodity requirements agreements, CenterPoint is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. We are not obligated to purchase any minimum quantities from CenterPoint or to purchase natural gas from them for any period longer than one month at a time. The natural gas we purchase under these agreements is priced at index-based prices, NYMEX or at mutually agreed-to fixed prices based on forward market prices. The index-based market prices are determined based on the prices published on the first of each month in Platts' Inside FERC's Gas Market Report, plus or minus an agreed-to fixed price adjustment per million British Thermal Units of natural gas purchased. Consequently, the price we pay for interstate natural gas is based on current market prices.

Our agreements with CenterPoint for the Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied service areas continue year-to-year unless canceled by either party by written notice at least sixty days prior to the annual anniversary date (April 30) of the agreement. In our fiscal year ended June 30, 2017, approximately 57% of our regulated natural gas supply was purchased under our agreements with CenterPoint.

Our regulated segment purchases natural gas from Midwest Energy Services, LLC ("Midwest") for injection into our underground natural gas storage field and to supply a portion of our system. We are not obligated to purchase any minimum quantities from Midwest, nor are we required to purchase natural gas for any periods longer than one month at a time. The natural gas is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. Our agreement with Midwest may be terminated upon 30 days prior written notice by either party. In our fiscal year ended June 30, 2017, approximately 42% of our regulated natural gas supply was purchased under our agreement with Midwest.

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

Transportation of Interstate Natural Gas Supply

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

Our agreements with Tennessee currently extend through October, 2019 and thereafter automatically renew for subsequent five-year terms unless Delta notifies Tennessee of its intent not to renew the agreements at least one year prior to the expiration of any renewal terms. At this time, we expect to renew our agreements with Tennessee. Subject to the terms of Tennessee's Federal Energy Regulatory Commission natural gas tariff, Tennessee is obligated under these agreements to transport up to 19,600 thousand cubic feet ("Mcf") per day for us. During fiscal 2017, Tennessee transported for us a total of 1,827,000 Mcf, or approximately 50% of our regulated supply requirements, under these agreements. We have natural gas storage agreements with Tennessee under the terms of which we reserve a defined storage space in Tennessee's storage fields, which we have assigned to CenterPoint, and we reserve the right to withdraw daily natural gas volumes up to certain specified fixed quantities. These natural gas storage agreements renew on the same schedule as our transportation agreements with Tennessee.

Under our agreements with Columbia Gas and Columbia Gulf, Columbia Gas is obligated to transport, including utilization of our defined storage space as required, up to 12,600 Mcf per day for us, and Columbia Gulf is obligated to transport up to a total of 4,300 Mcf per day for us. During fiscal 2017, Columbia Gas and Columbia Gulf transported for us a total of 266,000 Mcf, or approximately 7% of our regulated natural gas supply, under all of our agreements with them. Our transportation agreements with Columbia Gas continue on a year-to-year basis unless terminated by one of the parties. Our transportation agreements with Columbia Gulf extend through October, 2020 and may be extended by mutual agreement.

Columbia Gulf also transported additional volumes under agreements it has with Midwest to a point of interconnection between Columbia Gulf and us where we purchase the natural gas to inject into our storage field. The amounts transported and sold to us under the agreements Columbia Gulf has with Midwest for fiscal 2017 constituted 1,552,000 Mcf, or approximately 42% of our regulated natural gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, CenterPoint has an arrangement with Texas Eastern to transport the natural gas to us that we purchase from CenterPoint to supply our customers' requirements in specific geographic areas. In our fiscal year ended June 30, 2017, Texas Eastern transported approximately 11,000 Mcf of natural gas to our system, which constituted less than 1% of our natural gas supply.

Kentucky Natural Gas Supply

We have an agreement with Vinland Energy Operations, LLC ("Vinland") to purchase natural gas on a year-to-year basis unless terminated by one of the parties. We purchased 31,000 Mcf from Vinland during fiscal 2017. The price for the natural gas we purchase from Vinland is based on the index price of spot natural gas delivered to Columbia Gas in the relevant region as reported in Platts' Inside FERC's Gas Market Report. Vinland delivers this natural gas to our customer meters directly from its own pipelines. In fiscal 2017, the natural gas we purchased from Vinland constituted approximately 1% of our regulated natural gas supply.

Natural Gas in Storage

We own and operate an underground natural gas storage field that we use to store a significant portion of our natural gas supply needs. This storage capability permits us to purchase and store natural gas during the non-heating months and then withdraw and sell the natural gas during the peak usage months. We have a legal obligation to retire wells located at this underground natural gas storage facility. However, since we expect to utilize the storage facility as long as we provide natural gas to our customers, we have determined the wells have an indeterminate life and have therefore not recorded a liability associated with the cost to retire the wells.

Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services, which includes approval of our regulated rates and tariffs. We monitor our need to file requests with them for a general rate increase for our natural gas distribution and transportation services. The Kentucky Public Service Commission has historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of natural gas costs, and a reasonable rate of return on our rate base. Rate base consists primarily of our regulated segment's property, plant and equipment, natural gas in storage and unamortized debt expense offset by accumulated depreciation and certain deferred income taxes. Our regulated rates were most recently adjusted in our 2010 rate case. We do not have any matters pending before the Kentucky Public Service Commission which would have a material impact on our results of operations, financial position or cash flows.

Our pipe replacement program tariff allows us to adjust our regulated rates annually to earn a return on capital expenditures incurred subsequent to our last rate case which are associated with the replacement of pipe and related facilities. The pipe replacement program tariff is designed to additionally recover the costs associated with the mandatory retirement or relocation of facilities.

Our natural gas cost recovery tariff permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs and any bad debt expense related to natural gas cost. Although we are not required to file a general rate case to adjust rates pursuant to the natural gas cost recovery tariff, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered natural gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual natural gas costs were incurred.

Our weather normalization provision tariff provides for the adjustment of our rates to residential and small non-residential customers to reflect variations from thirty-year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

Additionally, we have a conservation and efficiency program tariff for our residential customers, which allows us to adjust our rates for activities performed through the program. Through this program, we perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high efficiency appliances. The program helps to align our interests with our residential customers' interests by reimbursing us for the gross margins on lost sales due to operating the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in seven of the cities we serve, and we continue to operate under the conditions of expired franchises in fifteen other cities we serve. In the other cities and areas we serve, there are no governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible. Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has not adversely affected our operations.

On March 17, 2017, we and PNG filed a joint application with the Kentucky Public Service Commission seeking regulatory approval of the Merger, as further discussed in Note 18 of the Notes to Consolidated Financial Statements. Under Kentucky Law, the Kentucky Public Service Commission had up to 120 days to approve the Merger and such approval is granted if the acquirer of a public utility demonstrates they possess the financial, technical, and managerial abilities to provide reasonable service. On August 15, 2017, the Kentucky Public Service Commission issued an order granting unconditional approval of the Merger and we anticipate closing to occur by September 30, 2017.

Non-Regulated Operations

Natural Gas Marketing

Our non-regulated segment includes three wholly-owned subsidiaries. Two of these subsidiaries, Delta Resources and Delgasco, purchase natural gas in the open market, including natural gas from Kentucky producers. We resell this natural gas to industrial customers on our distribution system and to others not on our system.

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

Our non-regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the natural gas to their plants or facilities. Additionally, some of our industrial customers are able to switch economically to alternative sources of energy. We continue to address these competitive concerns by offering these customers natural gas supply at competitive, market-based rates.

In our fiscal year ended June 30, 2017, approximately 98% of our non-regulated revenue was derived from our natural gas marketing activities. In our non-regulated segment, two customers each provided more than 5% of our operating revenues for 2017. CenterPoint provided approximately $4,744,000, $5,656,000 and $7,127,000 of non-regulated revenues during 2017, 2016 and 2015, respectively. Greystone, LLC provided approximately $15,889,000, $11,555,000 and $17,852,000 of non-regulated revenues during 2017, 2016 and 2015, respectively. There is no assurance that revenues from these customers will continue at these levels.

Natural Gas Production

Our subsidiary, Enpro, produces natural gas that is sold to Delgasco for resale in the open market when favorable market conditions arise. Item 2 further describes Enpro's oil and natural gas leases and production properties. Enpro produced a total of 111,000 Mcf of natural gas during 2017, which was approximately 2% of our non-regulated volumes sold.

Natural Gas Liquids

We process a portion of the natural gas in our distribution, transmission and storage system to extract liquids, enhancing the reliability and efficiency of our system. The profitability from the sales of the natural gas liquids is dependent on the amount of liquids extracted, the pricing for any such liquids as determined by a national non-regulated market and the volumes of natural gas liquids sold. In our fiscal year ended June 30, 2017, approximately 2% of our non-regulated revenue was derived from the sale of natural gas liquids.

Natural Gas Supply

Our non-regulated segment purchases natural gas from Midwest. Our underlying agreement with Midwest does not obligate us to purchase any minimum quantities, nor to purchase natural gas for any periods longer than one month at a time. The natural gas is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. Our agreement with Midwest may be terminated upon 30 days prior written notice by either party. Any purchase agreements to supply our non-regulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2017, 91% of our non-regulated natural gas supply was purchased under our agreement with Midwest.

Additionally, our non-regulated segment purchases natural gas from CenterPoint as needed. This spot purchasing arrangement is pursuant to an agreement with CenterPoint containing an evergreen clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from CenterPoint under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing natural gas for one or more months. The price of natural gas under this agreement is based on current market prices. In our fiscal year ended June 30, 2017, approximately 4% of our non-regulated natural gas supply was purchased under our agreement with CenterPoint.

We also purchase intrastate natural gas from Kentucky producers as needed at either current market prices, determined by industry publications, or at forward market prices.

We anticipate continuing our non-regulated activities and intend to pursue and increase these activities wherever practicable. We continue to consider acquisitions of additional production properties which are contiguous to our regulated distribution and transmission system as well as opportunities to process additional volumes of natural gas.

Merger with PNG Companies, LLC

On February 20, 2017, we entered into a Merger Agreement with PNG and Drake Merger Sub Inc. (“Merger Sub”), a new wholly owned subsidiary of PNG. The Merger Agreement provides for the merger of Merger Sub with and into Delta, with Delta surviving as a wholly owned subsidiary of PNG. A special meeting of shareholders was held on June 1, 2017 where shareholders voted and approved the Merger and on August 15, 2017, the Kentucky Public Service Commission issued an order granting unconditional approval of the Merger. At the effective time of the Merger, subject to customary closing conditions, each share of Delta common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $30.50 in cash per share, without interest, less any applicable withholding taxes. Upon consummation of the Merger, Delta common stock will be delisted from NASDAQ and the bank line of credit will be terminated. We anticipate closing to occur by September 30, 2017.

Subsequent to closing, a stub period dividend will be paid to Delta’s shareholders of record immediately prior to closing which is a prorated quarterly dividend calculated in accordance with the terms of the Merger Agreement.

In connection with this transaction, in 2017 we incurred $1,612,000 of Merger-related expenses for costs paid to outside parties, which are reflected in operation and maintenance in the Consolidated Statement of Income. This amount does not include the cost of company personnel participating in Merger-related activities. Refer to Note 13 of the Notes to Consolidated Financial Statements for a discussion of litigation related to the Merger.

Capital Expenditures

Capital expenditures during 2017 were $8.7 million and for 2018 are estimated to be $7.8 million. Our expenditures include system extensions, the replacement and improvement of existing transmission, distribution, gathering, production and storage systems as well as general facilities.

Financing

Our capital expenditures and operating cash requirements are primarily met through the use of internally generated funds. Our short-term bank line of credit is $40 million, all of which was available at June 30, 2017.

Our current bank line of credit extends through June 30, 2019, but will be terminated upon closing of the Merger. If the Merger does not close, the bank line of credit would be available to meet capital expenditure and operating cash requirements. Additionally, the amounts and types of future long-term debt and equity financings would depend upon our capital needs and market conditions.

We currently have long-term debt with contractual maturities of $50,500,000 in the form of our Series A Notes. The Series A Notes are unsecured, bear interest at 4.26% per annum and mature on December 20, 2031. Accrued interest on the Series A Notes is payable quarterly and we are required to make a $1,500,000 principal reduction payment on the Series A Notes each December.

Employees

On June 30, 2017, we had 148 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 under our “Investor Relations” tab, our Business Code of Conduct and Ethics, Vendor Code of Conduct and Ethics, annual report on Form 10-K, quarterly reports on Form 10-Q, extensible business reporting language (XBRL) interactive data files, 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 Securities and Exchange Commission (“SEC”). The SEC also maintains an Internet site http://www.sec.gov that contains reports, proxy and information statements and other information regarding Delta. The public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The SEC's phone number is 1-800-732-0330.

Consolidated Statistics

For the Years Ended June 30,	2017	2016	2015	2014	2013
Average Regulated Customers Served	34,532	34,415	34,384	34,490	34,701
Operating Revenues ($000) (a)					
Regulated revenues					
Natural gas sales	36,040	35,319	46,828	51,542	41,202
Natural gas transportation	8,901	9,225	9,366	9,163	9,037
Other	300	289	356	390	333
Total regulated revenues	45,241	44,833	56,550	61,095	50,572
Non-regulated revenues	27,045	22,888	33,507	38,792	34,238
Intersegment eliminations (b)	(3,446)	(3,591)	(3,869)	(4,041)	(4,145)
Total	68,840	64,130	86,188	95,846	80,665
System Throughput (Million Cu. Ft.) (a)					
Regulated					
Natural gas sales	2,531	2,623	3,261	3,351	3,057
Natural gas transportation	17,066	17,413	16,855	16,423	16,783
Total regulated throughput	19,597	20,036	20,116	19,774	19,840
Non-regulated	7,210	7,436	7,357	7,241	7,650
Intersegment eliminations (b)	(7,066)	(7,288)	(7,210)	(7,096)	(7,497)
Total	19,741	20,184	20,263	19,919	19,993
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	44	47	59	61	56
Lexington, Kentucky Degree Days					
Actual	3,476	3,765	4,964	4,855	4,667
Percent of 30 year average	77	83	110	107	104

(a) Additional financial information related to our segments can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 15 of the Notes to Consolidated Financial Statements.

(b) Intersegment eliminations represent the natural gas transportation costs from the regulated segment to the non-regulated segment.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

OUR BUSINESS, EARNINGS AND CASH REQUIREMENTS ARE HIGHLY WEATHER-SENSITIVE AND SEASONAL.

Our revenues vary from year-to-year, depending on weather conditions. We estimate that approximately 74% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can decrease the amount of natural gas we sell in any year, which would reduce our revenues and profits. Our weather normalization tariff, approved by the Kentucky Public Service Commission, only partially mitigates this risk. Under our weather normalization provision in our tariff, we adjust our rates for our residential and small non-residential customers to reflect variations from thirty-year average weather for our December through April billing cycles. Deviations from normal weather conditions and the seasonal nature of our business can create fluctuations in earnings and short-term cash requirements.

OUR ABILITY TO MEET CUSTOMERS' NATURAL GAS REQUIREMENTS MAY BE IMPAIRED IF CONTRACTED NATURAL GAS SUPPLIES AND INTERSTATE PIPELINE SERVICES ARE NOT AVAILABLE, ARE NOT DELIVERED IN A TIMELY MANNER OR IF FEDERAL REGULATIONS DECREASE OUR AVAILABLE CAPACITY.

We are responsible for acquiring sufficient natural gas supplies, interstate pipeline capacity and storage capacity to meet current and future customers' annual and seasonal natural gas requirements. We purchase almost all of our natural gas supply from interstate sources and rely on interstate pipelines to transport natural gas to our system. The Federal Energy Regulatory Commission regulates the transportation of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies. Additionally, federal legislation could restrict or limit drilling which could decrease the supply of available natural gas. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of natural gas. If we are not able to maintain a reliable and adequate natural gas supply and sufficient pipeline capacity to deliver that supply, we may be unable to meet our customers' requirements resulting in a loss of customers and decrease in profits.

OUR CUSTOMERS ARE ABLE TO BY-PASS OUR DISTRIBUTION AND TRANSMISSION SYSTEMS.

Our large-volume customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers. Customers for whom we transport natural gas could by-pass our transportation system to directly connect to interstate pipelines or other transportation providers. Customers may by-pass us in order to achieve lower prices for their natural gas or transportation services. Our large-volume customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution and transportation systems creates a risk of the loss of large-volume customers and thus could result in lower revenues and profits.

THE EFFECTS OF REGULATION ON OUR BUSINESS COULD DECREASE FUTURE PROFITABILITY.

The Kentucky Public Service Commission approves the rates we charge our regulated customers and has historically utilized cost-of-service ratemaking where our base rates are established based on normal operating expenses, exclusive of natural gas costs, and a reasonable rate of return on our rate base. We routinely evaluate our need to file for a general rate increase and in doing so weigh the need to increase rates with the potential risks associated with a rate case. The Kentucky Public Service Commission has ultimate discretion in determining what constitutes a reasonable return, what constitutes reasonable rates for our customers, and in any proceeding may disallow or limit the recovery of certain costs.

The Kentucky Public Service Commission sets our base rates using a twelve month test period which assumes revenues are generated based on thirty-year average temperatures and normal operating expenses. While the Kentucky Public Service Commission approves our rates, we may not earn our allowed return if we experience warmer than normal temperatures, infrequent or non-recurring expenses, increased expenses above amounts included in the test period or capital (debt and equity) which exceeds our rate base.

Additionally, there is a lag from the time a request is made to adjust rates to when the rates are approved and implemented as the Kentucky Public Service Commission reviews the reasonableness of any rate adjustment. Therefore, the need to adjust rates may be identified in one reporting period and the new rates implemented in a subsequent period.

Our regulated segment has recognized regulatory assets representing costs incurred in prior periods that are probable of recovery from customers in future rates. Disallowance of such costs in future proceedings before the Kentucky Public Service Commission could require us to write-off regulatory assets, which could have a material impact on our results of operations.

Our tariff provides for recovery of certain costs outside of a rate case which includes costs incurred under our natural gas cost recovery tariff, our pipe replacement program tariff and our conservation and efficiency program. Recovery of costs through these mechanisms is subject to the same risks associated with adjustment to our base rates.

VOLATILITY IN PRICES COULD REDUCE OUR PROFITS.

Significant increases or lack of stability in the price of natural gas will likely cause our regulated retail customers to increase conservation or switch to alternate sources of energy. Any decrease in the volume of natural gas we sell that is caused by such actions will reduce our revenues and profits. Higher prices also make it more difficult to add new customers. Significant decreases in the price of natural gas will likely cause our non-regulated segment's gross margins to decrease. The price of natural gas liquids is determined by a national non-regulated market, and decreases in the price could result in a decrease in our non-regulated gross margins.

THIRD PARTY RESTRICTIONS ON INTERSTATE AND OTHER PIPELINES DELTA INTERCONNECTS WITH CAN ADVERSELY AFFECT OUR RESULTS OF OPERATIONS OR CASH FLOWS.

The pipelines interconnected to Delta's system are owned and operated by third parties who can impose restrictions on the quantity and quality of natural gas they will accept into their pipelines. To the extent natural gas on Delta's system does not conform to these restrictions, Delta could experience a decrease in volumes sold or transported to these pipelines, which could have a negative impact on our financial position, results of operations and cash flows.

FUTURE PROFITABILITY OF THE NON-REGULATED SEGMENT IS IMPACTED BY FLUCTUATIONS IN NATURAL GAS PRICES AND A FEW INDUSTRIAL AND OTHER LARGE-VOLUME CUSTOMERS.

Our non-regulated customers are primarily industrial and other large-volume customers. Fluctuations in natural gas prices and the natural gas requirements of these customers can have a significant impact on the profitability of the non-regulated segment.

A DECLINE IN THE LIQUIDS PRESENT IN OUR SYSTEM OR LIQUIDS SALES PRICES COULD REDUCE OUR NON-REGULATED REVENUES.

To improve the operations of our distribution, transmission and storage system, we operate a facility that is designed to extract liquids from the natural gas in our system. We are able to sell these liquids at a price determined by a national non-regulated market. A reduction in the quantity of liquids present in our system, or reductions in the prices we receive for such liquids sales, could result in a reduction of the earnings of our non-regulated segment.

WE RELY ON ACCESS TO CAPITAL TO MAINTAIN LIQUIDITY.

To the extent that internally generated cash coupled with short-term borrowings under our bank line of credit is not sufficient for our operating cash requirements and normal capital expenditures, we may need to obtain additional financing. Additionally, market disruptions may increase our cost of borrowing or adversely affect our access to capital markets. Such disruptions could include: economic downturns, the bankruptcy of an unrelated energy company, general capital market conditions, market prices for natural gas, terrorist attacks or the overall financial health of the energy industry. There is no guarantee we could obtain needed capital in the future.

POOR INVESTMENT PERFORMANCE OF OUR DEFINED BENEFIT RETIREMENT PLAN HOLDINGS AND OTHER FACTORS IMPACTING PENSION COSTS COULD UNFAVORABLY IMPACT OUR LIQUIDITY AND RESULTS OF OPERATIONS.

Our cost of providing a non-contributory defined benefit retirement plan is dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding level of the plan, future government regulation and our required or voluntary contributions made to the plan. Without sustained growth in the pension investments over time to increase the value of the plan assets and depending upon the other factors impacting our costs as listed above, we could be required to fund our plan with additional significant amounts of cash. Additionally, investment performance less than our expected return on plan assets increases our pension expense in subsequent years. Both cash funding obligations and increased expense could have a material impact on our financial position, results of operations or cash flows.

WE ARE EXPOSED TO CREDIT RISKS OF CUSTOMERS AND OTHERS WITH WHOM WE DO BUSINESS.

Adverse economic conditions affecting, or financial difficulties of, customers and others with whom we do business could impair the ability of these customers and others to pay for our services or fulfill their contractual obligations or cause them to delay such payments or obligations. We depend on these customers and others to remit payments on a timely basis. Any delay or default in payment could adversely affect our financial position, results of operations or cash flows.

SUBSTANTIAL OPERATIONAL RISKS ARE INVOLVED IN OPERATING A NATURAL GAS DISTRIBUTION, TRANSPORTATION, LIQUIDS EXTRACTION AND STORAGE SYSTEM AND SUCH OPERATIONAL EVENTS COULD REDUCE OUR REVENUES AND INCREASE EXPENSES.

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

WE MAY FACE CERTAIN REGULATORY AND FINANCIAL RISKS RELATED TO PIPELINE SAFETY LEGISLATION.

Increased regulatory oversight over pipeline operations and increased investment to inspect pipeline facilities, upgrade pipeline facilities or control the impact of a breach of such facilities at the federal level could require additional operating expenses and capital expenditures to remain in compliance with any increased federal oversight. While we cannot predict with certainty the extent of these expenses and expenditures or when they might become effective, this could result in significant additional compliance costs to us and we may be unable to recover from our customers, through the regulatory process, all or some of these costs and an authorized rate of return on these costs.

HURRICANES, EXTREME WEATHER, WELL-HEAD OR PIPELINE DISASTERS COULD DISRUPT OUR NATURAL GAS SUPPLY AND INCREASE NATURAL GAS PRICES.

Hurricanes, extreme weather, well-head or pipeline disasters could damage production or transportation facilities, which could result in decreased supplies of natural gas, increased supply costs for us and higher prices for our customers.

OUR BORROWING ARRANGEMENTS INCLUDE VARIOUS FINANCIAL AND NEGATIVE COVENANTS AND A PREPAYMENT PENALTY THAT COULD RESTRICT OUR ACTIVITIES.

Our bank line of credit and Series A Notes contain financial covenants. A default on the performance of any single obligation incurred in connection with our borrowings, or a default on other indebtedness that exceeds $2,500,000, simultaneously creates an event of default with the bank line of credit and the Series A Notes. If we breach any of the financial covenants under these agreements, our debt repayment obligations under the bank line of credit and Series A Notes could be accelerated. For example, if we default we may not be able to refinance, repay all our indebtedness, pay dividends or have sufficient liquidity to meet our operating and capital expenditure requirements, all of which could result in a material adverse effect on our financial position, results of operations or cash flows.

OUR LONG-TERM DEBT ARRANGEMENTS LIMIT THE AMOUNT OF DIVIDENDS WE MAY PAY AND OUR ABILITY TO REPURCHASE OUR STOCK.

Under the terms of our 4.26% Series A Notes, the aggregate amount we may pay in dividends on our common stock and to repurchase our common stock is limited based on our cumulative net income and dividends paid. Consequently, as of June 30, 2017 our Series A Notes permit us to pay up to an additional $21,464,000 in dividends and for the repurchase of our common stock. However, if we fail to generate sufficient net income in the future, our ability to continue to pay our regular quarterly dividend may be impaired and the value of our common stock would likely decline.

A SECURITY BREACH COULD DISRUPT OUR INFORMATION TECHNOLOGY SYSTEMS, INTERRUPT THE NATURAL GAS SERVICE WE PROVIDE TO OUR CUSTOMERS, COMPROMISE THE SAFETY OF OUR NATURAL GAS DISTRIBUTION, TRANSMISSION, LIQUIDS EXTRACTION AND STORAGE SYSTEMS OR EXPOSE CONFIDENTIAL PERSONAL INFORMATION.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to information system disruptions or shutdowns, result in the interruption of our ability to provide natural gas to our customers or compromise the safety of our distribution, transmission, liquids extraction and storage systems. If such an attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, such an attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Additionally, a breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer, employee, vendor, investor or other sensitive data could have a material adverse effect on our reputation, operating results and financial condition. We could also be exposed to claims by persons harmed by such a breakdown or breach. Such a breakdown or breach could also materially increase the costs we incur to protect against such risks. There is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data are adequate to safeguard against all data security breaches.

FAILURE TO ATTRACT AND RETAIN AN APPROPRIATELY QUALIFIED WORKFORCE COULD UNFAVORABLY IMPACT OUR RESULTS OF OPERATIONS.

Certain situations, such as an aging workforce, mismatch of skill sets to complement future needs, or unavailability of a qualified workforce, may lead to increased operational risks and costs. As a result, we may be unable to hire an adequate number of individuals who are knowledgeable about public utilities and the natural gas industry or face a lengthy time period associated with skill development and knowledge transfer. Failure to address this risk may result in increased operational and safety risks as well as increased costs. Even if we have reasonable plans in place to address succession planning and workforce training, we cannot control the future availability of qualified labor. If we are unable to successfully attract and retain an appropriately qualified workforce, our financial position or results of operations could be negatively affected.

NEW LAWS OR REGULATIONS COULD HAVE A NEGATIVE IMPACT ON OUR FINANCIAL POSITION, RESULTS OF OPERATIONS OR CASH FLOWS.

Changes in laws and regulations, including new accounting standards and tax laws, could change the way in which we are required to record revenues, expenses, assets and liabilities. Additionally, governing bodies may choose to re-interpret laws and regulations. These changes could have a negative impact on our financial position, results of operations, cash flows or access to capital.

WE MAY FACE CERTAIN REGULATORY AND FINANCIAL RISKS RELATED TO CLIMATE CHANGE LEGISLATION.

Future proposals to limit greenhouse gas emissions, measured in carbon dioxide equivalent units, could adversely affect our operating and service costs and demand for our product. In the past, the United States Congress has considered legislative proposals to limit greenhouse gas emissions and the United States Environmental Protection Agency has adopted regulations to limit carbon emissions. Future legislation and the implementation of existing regulations could increase utility costs and prices charged to utility customers. Unless we are able to timely recover the costs of such impacts from customers through the regulatory process, costs associated with any such regulatory or legislative changes could adversely affect our financial position, results of operations or cash flows.

FAILURE TO COMPLETE THE MERGER COULD ADVERSELY AFFECT OUR STOCK PRICE AND FUTURE BUSINESS OPERATIONS AND FINANCIAL RESULTS.

Completion of the Merger is subject to risks, including the risks that certain closing conditions will not be satisfied. If we are unable to complete the Merger, holders of Delta common stock will not receive any payment for their shares pursuant to the Merger Agreement, our ongoing business may be adversely affected, and we would be subject to a number of risks, including the following:

- we will have paid certain significant transaction costs, including legal, financial advisory and filing, printing and mailing fees, and in certain circumstances, a termination fee to PNG Companies LLC of $4,340,000;
- the potential loss of key personnel during the pendency of the Merger as employees may experience uncertainty about their future roles with the combined company;
- we will have been subject to certain restrictions on the conduct of our business, which may prevent us from making certain acquisitions or dispositions, pursuing otherwise attractive business opportunities or making other changes to our business while the Merger is pending; and
- the trading price of our common stock may decline if the market believes the Merger may not be completed.

A failure to complete the Merger may also result in negative publicity, additional litigation against Delta or its directors and officers, and a negative impression of Delta in the investment community. The occurrence of any of these events, individually or in combination, could have a material adverse effect on our results of operations or the trading price of our common stock.

WE ARE SUBJECT TO CONTRACTUAL RESTRICTIONS IN THE MERGER AGREEMENT THAT MAY HINDER OPERATIONS PENDING THE MERGER.

The Merger Agreement restricts Delta, without PNG's consent, from certain specified actions until the Merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the Merger or termination of the Merger Agreement.

WE WILL BE SUBJECT TO VARIOUS UNCERTAINTIES WHILE THE MERGER IS PENDING THAT MAY CAUSE DISRUPTION AND MAY MAKE IT MORE DIFFICULT TO MAINTAIN RELATIONSHIPS WITH EMPLOYEES, SUPPLIERS OR CUSTOMERS.

Uncertainty about the effect of the Merger on employees, suppliers and customers may have an adverse effect on us. Although we have taken, and intend to continue to take, steps designed to reduce any adverse effects, these uncertainties may impair our abilities to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change or terminate existing business relationships with us or not enter into new relationships or transactions.

LITIGATION AGAINST DELTA AND ITS DIRECTORS CHALLENGING THE MERGER MAY PREVENT THE MERGER FROM BEING COMPLETED WITHIN THE AGREED-UPON TERMS AND THE ANTICIPATED TIMEFRAME.

Delta and its directors are named as defendants in class action lawsuits filed on behalf of shareholders challenging the Merger and potentially seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Although Delta has entered into a Memorandum of Understanding with the plaintiffs in the current litigation, which is subject to court approval, other litigation may be filed seeking an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, and such injunction may prevent the completion of the Merger in the expected timeframe or altogether.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own our corporate headquarters in Winchester, Kentucky. We own eleven buildings used for field operations in the cities we serve.

We own approximately 2,600 miles of natural gas gathering, transmission, distribution and storage 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 segment, as further discussed in Item 1.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business. Enpro owns interests in oil and natural gas leases on 10,300 acres located in southeastern Kentucky. Thirty-five natural gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 1.9 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in southeastern Kentucky. These properties have been leased to others for further drilling and development and Enpro reserves the option to participate in any wells drilled and also retains certain working and royalty interests in any production from future wells. We have performed no reserve studies on these properties. Enpro produced a total of 111,000 Mcf of natural gas during fiscal 2017 from all the properties described in this paragraph.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

(a) *Jacob Halberstam, et al v. Delta Natural Gas Company, Inc., et al*. Clark Circuit Court, Kentucky. The plaintiff filed this complaint on April 13, 2017, on behalf of himself and all Delta shareholders against Delta, its directors and PNG and Merger Sub. The plaintiff alleges that the defendants breached fiduciary duties to the Delta shareholders and aided and abetted breaches of fiduciary duties in connection with the Merger Agreement, under the terms of which Delta would be merged with and into Merger Sub, with Delta being the surviving corporation and becoming a wholly owned subsidiary of PNG. The plaintiff seeks to enjoin the consummation of the proposed transaction or, if the proposed transaction is closed, damages from Delta's directors.

(b) *Paul Parshall, et al. v. Delta Natural Gas Company, Inc.*, et al, United States District Court for the Eastern District of Kentucky at Lexington. The plaintiff filed this complaint on April 28, 2017, on behalf of himself and all Delta shareholders against Delta, its directors, PNG, Merger Sub and SteelRiver Infrastructure Fund North America, LP. The plaintiff alleges that the defendants violated Sections 14(a) and 20(a) of the Securities Exchange Act of 1934 in connection with the Merger Agreement. The complaint has been dismissed without prejudice.

(c) *Judy Cole, et al. v. Delta Natural Gas Company, Inc., et al*. Clark Circuit Court, Kentucky. The plaintiff filed this complaint on May 5, 2017, on behalf of herself and all Delta shareholders against Delta and its directors. The plaintiff alleges that the defendants breached fiduciary duties to the Delta shareholders in connection with the Merger Agreement and the proxy statement sent to Delta shareholders describing the transaction. The plaintiff seeks to enjoin the consummation of the proposed transaction.

Counsel for Delta, counsel for PNG, Merger Sub and SteelRiver Infrastructure Fund North America, LP and counsel for the plaintiffs in the three lawsuits described above have entered a confidential memorandum of understanding dated May 25, 2017, under the terms of which the litigation will be settled, subject to court approval, with Delta making additional disclosures to its shareholders, which has been done. It is anticipated that the plaintiffs will seek an order from the Clark Circuit Court requiring Delta to pay attorneys' fees and expenses of the plaintiffs. The amount of the anticipated fee request and any amount of settlement is unknown. During 2017, no expense has been recognized related to the fee request or settlement in the Consolidated Statement of Income. Delta is insured for such litigation, subject to a $1 million deductible.

We are not currently a party to any other legal proceedings that are expected to have a materially adverse impact on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

None.

PART II

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

We have paid cash dividends on our common stock each year since 1964. The frequency and amount of future dividends will depend upon our earnings, financial requirements and other relevant factors, including limitations imposed by our Series A Notes as described in Note 10 of the Notes to Consolidated Financial Statements.

Our common stock is listed on NASDAQ and trades under the symbol "DGAS". There were 1,283 record holders of our common stock as of August 31, 2017. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ stock market and the cash dividends declared per share.

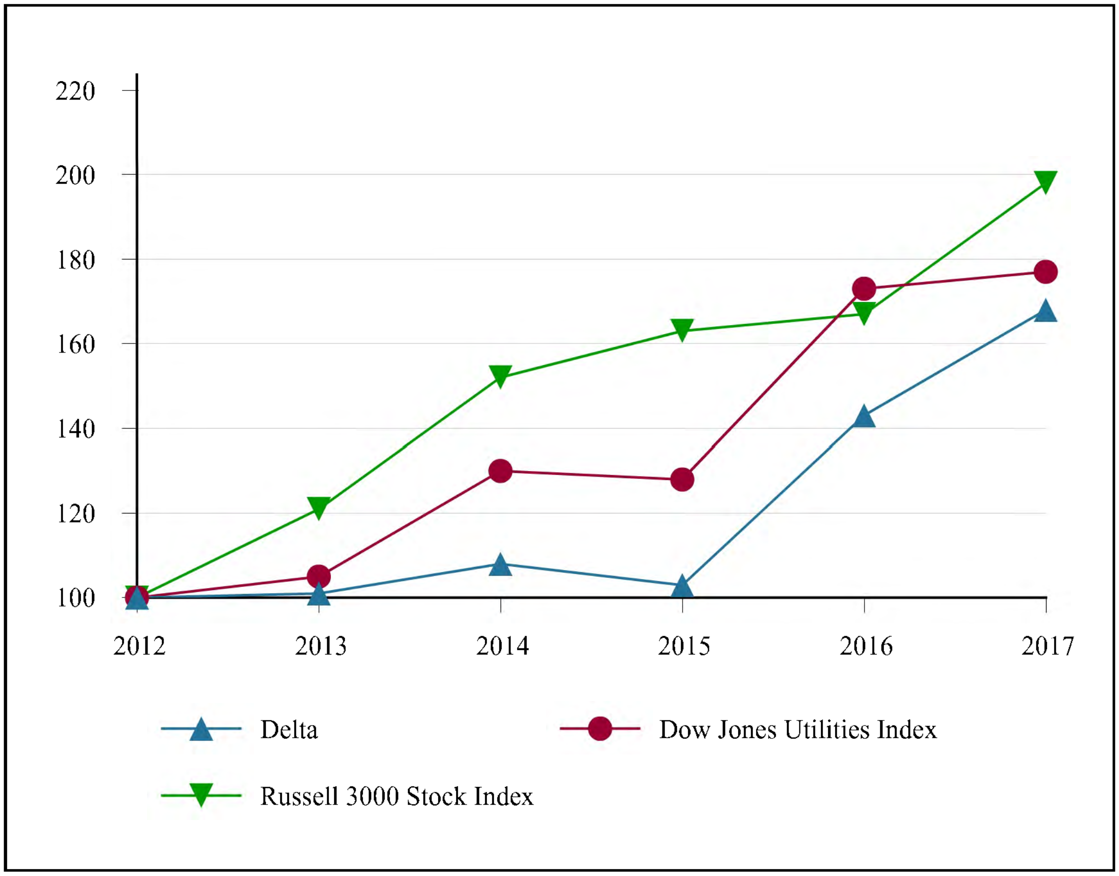
	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2017			
First	27.36	23.19	.2075
Second	31.29	22.06	.2075
Third	30.85	25.00	.2075
Fourth	30.82	29.70	.415 (a)
Fiscal 2016			
First	20.75	19.96	.205
Second	21.38	20.26	.205
Third	23.70	20.83	.205
Fourth	28.22	22.11	.205

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

(a) In contemplation of the Merger closing, Delta's Board of Directors declared the quarterly dividend for June's financial results on June 30, 2017. Historically, the dividend based on June's financial results is declared each August.

Comparison of Five-Year Cumulative Total Shareholder Return

The following graph sets forth a comparison of five-year cumulative total shareholder returns (equal to dividends plus stock price appreciation) among our common shares, the Dow Jones Utilities Index and the Russell 3000 Stock Index during the past five fiscal years. Information reflected on the graph assumes an investment of $100 on June 30, 2012 in each of our common shares, the Dow Jones Utilities Index and the Russell 3000 Stock Index. Cumulative total return assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.



	2012	2013	2014	2015	2016	2017
Delta	100	101	108	103	143	168
Dow Jones Utilities Index	100	105	130	128	173	177
Russell 3000 Stock Index	100	121	152	163	167	198

Item 6. Selected Financial Data

The following selected financial data is derived from the Company's audited consolidated financial statements and should be read in conjunction with those financial statements and notes thereto.

For the Years Ended June 30,	2017	2016	2015	2014	2013
Summary of Operations ($)					
Operating revenues	68,840,169	64,130,220	86,188,238	95,845,871	80,664,837
Operating income	11,003,516	11,433,992	12,963,861	15,603,439	13,188,679
Net income	5,516,343	5,529,378	6,496,081	8,275,128	7,200,776
Earnings per common share					
Basic and diluted	.77	.78	.92	1.19	1.05
Cash dividends declared per common share (a)	1.0375	.82	.80	.76	.72
Weighted Average Number of Common Shares					
Basic and Diluted	7,118,170	7,066,925	7,002,694	6,918,725	6,843,455
Total Assets ($)	189,956,927	188,879,129	187,711,166	185,934,857	183,832,911
Capitalization ($)					
Common shareholders' equity	76,494,995	77,726,969	77,221,654	74,728,352	70,005,415
Long-term debt	48,929,196	50,422,796	51,916,296	53,409,696	54,902,896
Total capitalization	125,424,191	128,149,765	129,137,950	128,138,048	124,908,311
Current Portion of Long-Term Debt ($)	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
Other Items ($)					
Capital expenditures	8,725,635	6,302,666	9,010,876	8,077,642	7,179,473
Property, plant and equipment	249,611,353	241,833,771	236,780,490	229,367,319	223,545,925

(a) In contemplation of the Merger closing, Delta's Board of Directors declared the quarterly dividend for June's financial results on June 30, 2017. Historically, the dividend based on June's financial results is declared each August.

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

Overview of 2017 and Future Outlook

Overview

The following is a discussion of the segments we operate, our corporate strategy for the conduct of our business within these segments and significant events that have occurred during 2017. Our Company has two segments: a regulated segment, and a non-regulated segment. Our regulated segment includes our natural gas distribution and transportation services, which are regulated by the Kentucky Public Service Commission. Our non-regulated segment includes our natural gas marketing activities and the sales of natural gas liquids.

Earnings from the regulated segment are primarily influenced by sales and transportation volumes, the rates we charge our customers and the expenses we incur. In order for us to achieve our strategy of maintaining reasonable long-term earnings, cash flow and stock value, we must successfully manage each of these factors. Regulated sales volumes are temperature sensitive and in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. The impact of winter temperatures on our revenues is partially reduced by our ability to adjust our winter rates for residential and small non-residential customers based on the degree to which actual winter temperatures deviate from historical average temperatures.

Our non-regulated segment markets natural gas to large-volume customers. We endeavor to enter sales agreements matching supply with estimated demand while providing an acceptable gross margin. The non-regulated segment produces a portion of its natural gas supply, which is stored and sold when favorable market conditions arise. The non-regulated segment also sells liquids extracted from natural gas.

Consolidated income per common share of $0.77 for 2017 decreased, as compared to our consolidated income of $0.78 for 2016, due to incurring $1,612,000 of Merger-related costs which were partially offset by increased non-regulated revenues, net of natural gas costs (as further discussed in Results of Operations). Our non-regulated segment experienced increased revenues, net of natural gas costs, due to increased sales prices for natural gas and natural gas liquids and the sale of our production inventory. Our non-regulated segment produces and stores natural gas which it sells when favorable market conditions arise.

Future Outlook

Future profitability of the regulated segment is contingent on the adequate and timely adjustment of the rates we charge our regulated customers and our ability to earn our allowed return. The Kentucky Public Service Commission approves these rates. We monitor our need to file for a general rate increase for our regulated services with the Kentucky Public Service Commission who has historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of natural gas costs, and a reasonable rate of return on our rate base. Rate base consists primarily of our regulated segment's property, plant and equipment, natural gas in storage and unamortized debt expense offset by accumulated depreciation and certain deferred income taxes. The Kentucky Public Service Commission determines what constitutes reasonable rates for our customers and in any proceeding may disallow or limit the recovery of certain costs and has ultimate discretion determining what constitutes a reasonable return. We may not earn our allowed return if we experience warmer than normal temperatures, infrequent or non-recurring expenses, increased expenses above amounts included in the test period or capital (debt and equity) which exceeds our rate base. The regulated segment's largest expense is natural gas supply, which we are permitted to pass through to our customers. We manage remaining expenses through budgeting, approval and review.

Future profitability of the non-regulated segment is dependent on the business plans of some of our industrial and other large-volume customers and the market prices of natural gas and natural gas liquids, all of which are out of our control. We anticipate our non-regulated segment will continue to contribute to our consolidated net income in fiscal 2018. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated revenues, net of natural gas costs, related to our natural gas marketing activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated revenues, net of natural gas costs, related to our natural gas marketing activities. We process a portion of the natural gas in our distribution, transmission and storage system to extract liquids, enhancing the reliability and efficiency of our system. The profitability from the sales of the natural gas liquids is dependent on the amounts of liquids extracted and the prices for any such liquids as determined by a national non-regulated market.

Proposed Merger

On February 20, 2017, we entered into an Agreement and Plan of Merger (“Merger Agreement”) with PNG Companies, LLC (“PNG”), hereinafter referred to as the “Merger”. For further information, see Note 18 of the Notes to Consolidated Financial Statements.

Liquidity and Capital Resources

Sources and Uses of Cash

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes, share-based compensation and changes in working capital. Our sales and cash requirements are seasonal. The largest portion of our sales occurs during the heating months (December - April), whereas significant cash requirements for the purchase of natural gas for injection into our storage field and capital expenditures occur during non-heating months. Therefore, when cash provided by operating activities is not sufficient to meet our capital requirements, our ability to maintain liquidity depends on our bank line of credit. The current bank line of credit with Branch Banking and Trust Company extends through June 30, 2019 and permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit as of June 30, 2017 or June 30, 2016.

Cash and cash equivalents were $13,279,000 at June 30, 2017 compared with $18,607,000 at June 30, 2016 and $16,924,000 at June 30, 2015. These changes in cash and cash equivalents are summarized in the following table:

$(000)	2017	2016	2015
Provided by operating activities	10,253	14,740	18,765
Used in investing activities	(8,521)	(6,087)	(8,910)
Used in financing activities	(7,060)	(6,971)	(6,607)
(Decrease) increase in cash and cash equivalents	(5,328)	1,682	3,248

In 2017, cash provided by operating activities decreased $4,487,000 (30%), as compared to 2016, due to a $4,597,000 increase in cash paid for natural gas partially offset by a $2,234,000 increase in cash received from customers, as further discussed in Results of Operations. Additionally, discretionary contributions to our deferred benefit retirement plan increased $1,000,000, as compared to the prior year, and we incurred $1,612,000 in Merger-related costs.

In 2016, cash provided by operating activities decreased $4,025,000 (21%), as compared to 2015, due to a $22,074,000 decrease in cash received from customers partially offset by a $16,192,000 decrease in cash paid for natural gas, as further discussed in Results of Operations. Additionally, cash paid for income taxes decreased $1,249,000 as a result of decreased earnings.

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

In 2017 and 2016 there were no significant changes in cash used in financing activities, as compared to 2016 and 2015, respectively.

Cash Requirements

Our capital expenditures result in a continued need for cash. These capital expenditures are being made for system extensions and for the replacement and improvement of existing transmission, distribution, gathering, production and storage systems, as well as general facilities. We expect our capital expenditures for fiscal 2018 to be approximately $7.8 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2017:

	Payments Due by Fiscal Year				
$(000)	2018	2019 - 2020	2021 - 2022	After 2022	Total
Interest payments (a)	2,172	4,043	3,788	14,471	24,474
Long-term debt (b)	1,500	3,000	3,000	43,000	50,500
Pension contributions (c)	500	1,000	1,000	4,500	7,000
Natural gas purchases (d)	350	199	—	—	549
Total contractual obligations (e)	4,522	8,242	7,788	61,971	82,523

(a) Our long-term debt, notes payable and customers' deposits all require interest payments. Interest payments are projected based on fiscal 2017 interest payments until the underlying obligation is satisfied.

(b) See Note 10 of the Notes to Consolidated Financial Statements for a description of this debt.

(c) This represents currently projected contributions to the defined benefit retirement plan through 2031, as recommended by our actuary.

(d) As of June 30, 2017, our non-regulated segment had forward purchase contracts for natural gas which had minimum purchase obligations that expire in June, 2019. The remainder of our natural gas purchase contracts are either requirements-based contracts, or contracts with a minimum purchase obligation extending for a time period not exceeding one month.

(e) We have other long-term liabilities which include deferred income taxes ($44,815,000), regulatory liabilities ($1,135,000), asset retirement obligations ($4,031,000) and deferred compensation ($1,219,000). Based on the nature of these items their expected settlement dates cannot be estimated.

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

See Note 13 of the Notes to Consolidated Financial Statements for other commitments and contingencies.

Sufficiency of Future Cash Flows

Our ability to maintain liquidity, finance capital expenditures and pay dividends is contingent on the adequate and timely adjustment of the regulated rates we charge our customers. The Kentucky Public Service Commission approves these rates and we monitor our need to file for rate increases for our regulated segment. Our regulated base rates were most recently adjusted in our 2010 rate case and became effective in October, 2010. We expect that cash provided by operations combined with our bank line of credit will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months.

Our Series A Notes are unsecured, bear interest at a rate of 4.26% per annum, which is payable quarterly, and mature on December 20, 2031. We are required to make an annual $1,500,000 principal payment on the Series A Notes each December. Any refinance of the Series A Notes, or any additional prepayments of principal, may be subject to a prepayment penalty.

With our bank line of credit agreement and Series A Notes, we have agreed to certain financial covenants. Noncompliance with these covenants can make the obligations immediately due and payable. We have agreed to the following financial covenants:

- The Company must at all times maintain a tangible net worth of at least $25,800,000.

- The Company must at the end of each fiscal quarter maintain a total debt to capitalization ratio of no more than 70%. The total debt to capitalization ratio is calculated as the ratio of (i) the Company's total debt to (ii) the sum of the Company's shareholders' equity plus total debt.

- The Company must maintain a fixed charge coverage ratio for the twelve months ending each quarter of not less than 1.20x. The fixed charge coverage ratio is calculated as the ratio of (i) the Company's earnings adjusted for certain unusual or non-recurring items, before interest, taxes, depreciation and amortization plus rental expense to (ii) the Company's interest and rental expense.

- The Company may not pay aggregate dividends on its capital stock (plus amounts paid in redemption of its capital stock) in excess of the sum of $15,000,000 plus the Company's cumulative earnings after September 30, 2011 adjusted for certain unusual or non-recurring items.

The following table shows the required and actual financial covenants under our Series A Notes as of June 30, 2017:

	Requirement	Actual
Tangible net worth	no less than $25,800,000	$75,852,000
Debt to capitalization ratio	no more than 70%	40%
Fixed charge coverage ratio	no less than 1.20x	7.68x
Dividends paid	no more than $48,619,000	$32,672,000

Our 4.26% Series A Notes restrict us from:

- with limited exceptions, granting or permitting liens on or security interests in our properties,

- selling a subsidiary, except in limited circumstances,

- incurring secured debt, or permitting a subsidiary to incur debt or issue preferred stock to any third party, in an aggregate amount that exceeds 10% of our tangible net worth,

- changing the general nature of our business,

- merging with another company, unless (i) we are the survivor of the merger or the survivor of the merger is another domestic company that assumes the 4.26% Series A Notes, (ii) there is no event of default under the 4.26% Series A Notes and (iii) the continuing company has a tangible net worth at least as high as our tangible net worth immediately prior to such merger, or

- selling or transferring assets, other than (i) the sale of inventory in the ordinary course of business, (ii) the transfer of obsolete equipment and (iii) the transfer of other assets in any 12 month period where such assets constitute no more than 5% of the value of our tangible assets and, over any period of time, the cumulative value of all assets transferred may not exceed 15% of our tangible assets.

Without the consent of the bank that has extended to us our bank line of credit or terminating our bank line of credit, we may not:

- merge with another entity;

- sell a material portion of our assets other than in the ordinary course of business,

- issue stock which in the aggregate exceeds thirty-five percent (35%) of our outstanding shares of common stock, or

- permit any person or group of related persons to hold more than twenty percent (20%) of the Company's outstanding shares of stock.

Furthermore, the agreement governing our 4.26% Series A Notes contains a cross-default provision which provides that we will be in default under the 4.26% Series A Notes if we are in default on any other outstanding indebtedness that exceeds $2,500,000. Similarly, the loan agreement governing the bank line of credit contains a cross-default provision which provides that we will be in default under the bank line of credit if we are in default under our 4.26% Series A Notes and fail to cure the default within ten days of notice from the bank. We were in compliance with the covenants under our bank line of credit and 4.26% Series A Notes for all periods presented in the Consolidated Financial Statements.

Critical Accounting Policies and Estimates

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

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

Regulatory Accounting

Our accounting policies reflect the effects of the ratemaking process in accordance with regulatory accounting standards. Our regulated segment continues to be cost-of-service rate regulated, and we believe the application of regulatory accounting standards to that segment is appropriate. If, as a result of a change in circumstances, it is determined that the regulated segment no longer meets the criteria to apply regulatory accounting, the regulated segment would have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of regulatory accounting standards results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the Kentucky Public Service Commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base this conclusion on certain factors, including changes in the regulatory environment, recent rate orders issued by the Kentucky Public Service Commission and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred, or they represent probable future refunds to customers.

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

Defined Benefit Retirement Plan

We have a non-contributory, defined benefit retirement plan covering all eligible employees hired prior to May 9, 2008. The net periodic benefit costs (“pension costs”) for our defined benefit retirement plan as described in Note 6 of the Notes to Consolidated Financial Statements are dependent upon numerous factors resulting from actual plan experience and assumptions concerning future experience. These costs, for example, are impacted by employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plan and earnings on plan assets. Additionally, changes made to the provisions of the plan may impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs. For the years ended June 30, 2017, 2016 and 2015, we recorded pension costs for our defined benefit retirement plan of $1,312,000, $812,000 and $493,000, respectively.

Changes in pension obligations associated with the above factors may not be immediately recognized as pension costs in the Consolidated Statements of Income, but may be deferred and amortized over the average remaining service period of the active plan participants. As of June 30, 2017, $7,126,000 of accumulated net losses have been deferred for amortization as pension costs into future periods.

Our defined benefit retirement plan's assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns 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 pension costs in future periods.

In selecting our discount rate assumption we considered rates of return on high-quality fixed-income investments that are expected to be available through the maturity dates of the pension benefits. Our expected long-term rate of return on the defined benefit retirement plan's assets was 5.5% for 2017 and was based on our targeted asset allocation assumption for 2017 of approximately 65% equity investments and approximately 35% fixed income investments. Our targeted investment allocation for equity investments includes allocations to domestic, global and real estate markets. For additional diversification, we also invest in absolute return strategy mutual funds, which include both equity and fixed income securities. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. The plan has amended its investment policy to allow for liability driven investments which, over time, will match a portion of the plan's liability with the underlying assets. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

The funded status of our plan reflects investment gains or losses in the year in which they occur based on the market value of assets at the measurement date.

Based on an assumed long-term rate of return of 5.5%, discount rate of 3.75%, and various other assumptions, we estimate that our pension costs associated with our defined benefit retirement plan will decrease from $1,312,000 in 2017 to $729,000 in 2018. Modifying the expected long-term rate of return on our defined benefit retirement plan assets by .25% would change pension costs for 2018 by approximately $81,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $143,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $151,000.

Unbilled Revenues and Natural Gas Costs

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

New Accounting Pronouncements

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

Forward-Looking Statements

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

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

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

Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are not guarantees of future performance and are based upon currently available competitive, financial and economic data along with our operating plans.

Item 1A lists factors that, among others, could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results.

Results of Operations

Gross Margins

Our operating revenues are derived primarily from the sale and delivery of natural gas, the sale of natural gas liquids and the provision of natural gas transportation services. Our operating revenues are significantly impacted by the prices we pay for natural gas. Therefore, we view gross margins as an important performance measure of the core profitability of our operations and believe investors benefit from having access to the same financial measures that our management uses. We define "gross margins" as natural gas sales less the corresponding purchased natural gas expenses, plus transportation, natural gas liquids and other revenues. Gross margins can be derived directly from our Consolidated Statements of Income included in Item 8, as follows:

($000)	2017	2016	2015
Operating revenues	68,840	64,130	86,188
Regulated purchased natural gas	(12,562)	(11,704)	(22,729)
Non-regulated purchased natural gas	(19,981)	(17,621)	(26,713)
Consolidated gross margins	36,297	34,805	36,746

Operating Income, as presented in the Consolidated Statements of Income, is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). Gross margin is a "non-GAAP financial measure", as defined in accordance with SEC rules.

Natural gas prices are determined by a non-regulated national market. Therefore, the prices that we pay for natural gas fluctuate with national supply and demand. See Item 7A for a discussion of our forward contracts.

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

($000)	2017 compared to 2016	2016 compared to 2015
Increase (decrease) in gross margins		
Regulated segment		
Natural gas sales	(137)	(484)
Natural gas transportation	(324)	(141)
Other	11	(67)
Intersegment elimination (a)	145	278
Total	(305)	(414)
Non-regulated segment		
Natural gas sales	1,659	(616)
Natural gas liquids	274	(578)
Other	9	(55)
Intersegment elimination (a)	(145)	(278)
Total	1,797	(1,527)
Increase (decrease) in consolidated gross margins	1,492	(1,941)
(%)		
Percentage increase (decrease) in volumes		
Regulated segment		
Natural gas sales (Mcf)	(3)	(20)
Natural gas transportation (Mcf)	(2)	3
Non-regulated segment		
Natural gas sales (Mcf)	(3)	1
Natural gas liquids (gallons)	(7)	(22)

(a) Intersegment eliminations represent the natural gas transportation costs from the regulated segment to the non-regulated segment.

Heating degree days were 77% of the normal thirty-year average temperatures for fiscal 2017, as compared with 83% and 110% of normal temperatures for 2016 and 2015, respectively. A heating degree day is each degree that the average of the high and the low temperatures for a day is below 65 degrees in a specific geographic location. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to estimate the demand for natural gas. Normal temperatures are based on historical thirty-year average heating degree days, as calculated from data provided by the National Weather Service for the same geographic location.

In 2017, consolidated gross margins increased $1,492,000 (4%), as compared to 2016, primarily due to increased non-regulated gross margins on natural gas sales and natural gas liquids. Gross margins on non-regulated gas sales increased due to the sale of our non-regulated segment's production inventory and increased sales prices. Gross margins on the sale of natural gas liquids increased due to a 128% increase in the average sales price.

In 2016, consolidated gross margins decreased $1,941,000 (5%), as compared to 2015, due to decreased non-regulated gross margins on natural gas sales and decreased sales prices of natural gas liquids. Gross margins on non-regulated natural gas sales decreased due to the prior year sale of our non-regulated segment's production inventory and decreased sales prices, partially offset by an increase in volumes sold. During 2015, we experienced a 46% decline in the average sales price of natural gas liquids. We process a portion of the natural gas in our distribution, transmission and storage system to extract liquids, enhancing the reliability and efficiency of our system. The profitability from the sales of the natural gas liquids is dependent on the amounts of liquids extracted and the prices for any such liquids as determined by a national non-regulated market.

Operating Expenses

In 2017, operation and maintenance increased $1,998,000 (14%), as compared to 2016, due to incurring $1,612,000 of Merger-related expenses for costs paid to outside parties related to the proposed Merger, as further discussed in Note 18 of the Notes to Consolidated Financial Statements, and a $500,000 increase in the net periodic benefit cost for our defined benefit retirement plan.

In 2017 and 2016, there were no significant changes in depreciation and amortization and taxes other than income taxes as compared to 2016 and 2015, respectively.

In 2016, there were no significant changes to operation and maintenance, as compared to 2015.

Other Income

In 2017, other income increased $202,000 (5,050%), as compared to 2016, due to an increase in the earnings from the supplemental retirement trust and an increase in interest received on the cash surrender value of our life insurance policies. The increase in the earnings from the supplemental retirement trust was offset by an increase in operating expense resulting from a corresponding change in the liability of the trust.

In 2016, there were no significant changes in other income, as compared to 2015.

Interest Charges

In 2017 and 2016, there were no significant changes in interest on long-term debt, amortization of debt expense and other interest expense, as compared to 2016 and 2015, respectively.

Income Tax Expense

In 2017, there were no significant changes in income tax expense, as compared to 2016.

In 2016, income tax expense decreased $515,000 (13%) due to decreases in net income before income taxes, as compared to 2015. There were no significant changes in our effective tax rate for 2017 and 2016, as compared to 2016 and 2015, respectively.

Basic and Diluted Earnings Per Common Share

For 2017 and 2016, our basic and diluted earnings per common share changed, as compared to 2016 and 2015, respectively, 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 as well as those awarded through our Incentive Compensation Plan. Our computation of basic and diluted earnings per share is set forth in Note 11 of the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We purchase our natural gas supply primarily through a combination of requirements contracts with no minimum purchase obligations, monthly spot purchase contracts and forward purchase contracts. The price we pay for natural gas acquired under forward purchase contracts is fixed prior to the delivery of the natural gas. Additionally, we inject some of our natural gas purchases into our underground natural gas storage facility in the non-heating months and withdraw this natural gas from storage for delivery to customers during the heating months. For our regulated segment, we utilize requirements contracts, spot purchase contracts and our underground storage to meet our regulated customers' natural gas requirements, all of which have minimal price risk because we are permitted to pass these natural gas costs on to our regulated customers through our natural gas cost recovery tariff.

Price risk for the non-regulated segment is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to changes in the market price of natural gas on uncommitted natural gas inventory of our non-regulated segment. The pricing of the natural gas liquids sold by our non-regulated segment is determined in the national non-regulated market.

None of our natural gas contracts are accounted for using the fair value method of accounting. While some of our natural gas purchase and natural gas sales contracts meet the definition of a derivative, we have designated these contracts as normal purchases and normal sales. As of June 30, 2017, we had forward purchase contracts through June, 2019 totaling $549,000 which are at a fixed price and not impacted by changes in the market price of natural gas.

When we have a balance outstanding on our variable rate bank line of credit, we are exposed to risk resulting from changes in interest rates. The interest rate on our bank line of credit with Branch Banking and Trust Company is benchmarked to the monthly London Interbank Offered Rate. There were no borrowings outstanding on our bank line of credit as of June 30, 2017 or June 30, 2016. As of June 30, 2017 and June 30, 2016, the weighted average interest rate on our bank line of credit was 2.3% and 1.5%, respectively. During 2017 and 2016, we did not have any borrowings on our bank line of credit. A one percent (one hundred basis point) increase in our average interest rate would not have impacted our annual pre-tax net income.

Item 8. Financial Statements and Supplementary Data

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

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2017 and based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal year ended June 30, 2017 and found no change that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of June 30, 2017 based on the framework in *Internal Control - Integrated Framework* issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of June 30, 2017.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2017, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended June 30, 2017 of the Company and our report dated September 1, 2017 expressed an unqualified opinion on those consolidated financial statements and the financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio

September 1, 2017

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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

Our Board of Directors has adopted charters for the Audit, Corporate Governance and Compensation and Executive Committees of the Board of Directors as well as Corporate Governance Guidelines. These documents can be found on our website by going to the following address: http://www.deltagas.com/governance.

A printed copy of any of the materials referred to above can be obtained by contacting us at the following address:

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

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

The other information required by this Item is contained under the captions "Election of Directors", "Board Leadership, Committees and Meetings", "Executive Officers", "Certain Relationships and Related Transactions" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2017. We incorporate that information in this document by reference.

Item 11. Executive Compensation

Information in response to this item is contained under the captions "Director Compensation", "Corporate Governance and Compensation Committee Interlocks and Insider Participation", "Compensation Discussion and Analysis", "Compensation Risks", "Corporate Governance and Compensation Committee Report", "Summary Compensation Table", "Grants of Plan Based Awards", "Outstanding Equity Awards at Fiscal Year-End", "Retirement Benefits", "Potential Payments Upon Termination Or Change in Control" and "Termination Table" in our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2017. We incorporate that information in this document by reference.

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

Equity Compensation Plans

Pursuant to our shareholder approved incentive compensation plan, we have the ability to grant stock, performance shares and restricted stock to employees, officers and directors. The plan does not provide for the awarding of options, warrants or rights. We do not have any equity compensation plans which have not been approved by our shareholders.

The following table sets forth certain information with respect to our equity compensation plan at June 30, 2017:

Column A	Column B	Column C
Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in Column A)
—	—	750,902

The other information required by this Item is contained under the captions "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Management" in our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2017. We incorporate that information in this document by reference.

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

The information required by this item is contained under the captions "Election of Directors", "Board Leadership, Committees and Meetings" and "Certain Relationships and Related Transactions" in our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2017. We incorporate that information in this document by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is contained under the caption "Audit Committee Report" in our definitive Proxy Statement for the 2017 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2017. We incorporate that information in this document by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedule

(a) Financial Statements, Schedule and Exhibits

(1) Financial Statements
See Index at Item 8

(2) Financial Statement Schedule
See Index at Item 8

(3) Exhibits

Exhibit No.	
3.1	Registrant's Amended and Restated Articles of Incorporation (dated November 16, 2006) are incorporated herein by reference to Exhibit 3(i) to Registrant's Form 10-K/A (File No. 000-08788) for the period ended June 30, 2007.
3.2	Registrant's Amended and Restated By-Laws (dated August 14, 2015) are incorporated herein by reference to Exhibit 3.1 to Registrant's Form 8-K (File No. 000-8788) dated August 17, 2015.
4	Note Purchase and Private Shelf Agreement dated December 8, 2011 in respect of 4.26% Senior Notes, Series A, due December 20, 2031 is incorporated herein by reference to Exhibit 10.01 to Registrant's Form 8-K (File No. 000-08788) dated December 13, 2011.
10.01	Natural Gas Sales Agreement, dated May 1, 2000 by and between Atmos Energy Marketing, LLC and Registrant is incorporated herein by reference to Exhibit 10(c) to Registrant's Form S-2/A (Reg. No. 333-100852) dated December 13, 2002. Atmos Energy Marketing, LLC is now CenterPoint Energy Services, Inc.
10.02	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.
10.03	Natural Gas Sales Agreement, dated May 1, 2003, by and between Atmos Energy Marketing, LLC and Registrant is incorporated herein by reference to Exhibit 10(d) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2003. Atmos Energy Marketing, LLC is now CenterPoint Energy Services, Inc.
10.04	Base contract for the Sale and Purchase of Natural Gas, dated May 1, 2005 and Exhibit A, dated May 1, 2010 by and between Atmos Energy Marketing, LLC and Registrant are incorporated herein by reference to Exhibit 10.04 to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2012. Atmos Energy Marketing, LLC is now CenterPoint Energy Services, Inc.
10.05	Base contracts for the Sale and Purchase of Natural Gas, dated May 1, 2013, by and between Midwest Energy L.L.C. and Registrant are incorporated herein by reference to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2013.
10.06	Natural 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/A (Reg. No. 333-100852) dated December 13, 2002.
10.07	Agreement to transport natural gas between Nami Resources Company L.L.C. and Registrant, dated March 10, 2005 is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated March 23, 2005.
10.08	Amendment, dated July 22, 2010, of agreement to transport natural gas between Nami Resources Company, L.L.C. and Registrant is incorporated herein by reference to Exhibit 10(f) to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2010.
10.09	GTS Service Agreements, dated October 29, 2015 (Service Agreement Nos. 37,813, 37,814 and 37,815) and Appendix A to respective Service Agreements, effective November 1, 2015, by and between Columbia Gulf Transmission, LLC and Registrant are incorporated herein by reference to Exhibit 10.01 to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2015.
10.10	FTS-1 Service Agreements, dated October 29, 2015, (Service Agreement Nos. 43,827, 43,828 and 43,829) and Appendix A to respective Service Agreements, effective November, 2010, by and between Columbia Gulf Transmission, LLC and Registrant are incorporated herein by reference to Exhibit 10.02 to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2015.
10.11	Underground Natural 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 Natural 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.

10.12	Oil and Natural Gas Lease, dated July 19, 1995, by and between Meredith J. Evans and Helen Evans and Paddock Oil and Gas, Inc.; Assignment, dated June 15, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; Assignment, dated August 31, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant is incorporated herein by reference to Exhibit 10(o) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.
10.13	Natural 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.
10.14	Natural 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.
10.15	Deed and Perpetual Natural 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.
10.16	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/A (Reg. No. 333-100852) dated December 13, 2002.
10.17	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.
10.18	Modification Agreement extending to October 31, 2004 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant 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, 2003.
10.19	Modification Agreement extending to October 31, 2005 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant 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, 2004.
10.20	Modification Agreement extending to October 31, 2007 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated August 19, 2005.
10.21	Modification Agreement extending to October 31, 2009 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2007.
10.22	Modification Agreement extending to June 30, 2011 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated June 30, 2009.
10.23	Modification Agreement extending to June 30, 2013 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated June 30, 2011.
10.24	Modification Agreement extending to June 30, 2015 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated June 30, 2013.
10.25	Modification Agreement extending to June 30, 2017 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated June 30, 2015.
10.26	Modification Agreement extending to June 30, 2019 the Promissory Note and Loan Agreement dated October 31, 2002 between Branch Banking and Trust Company and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated June 30, 2017.
10.27	Employment agreement dated March 1, 2000, between Glenn R. Jennings, Registrant's Chairman of the Board, President and Chief Executive Officer, and Registrant is incorporated herein by reference to Exhibit (k) to Registrant's Form 10-Q (File No. 000-08788) dated March 31, 2000.
10.28	Officer agreements dated March 1, 2000, between two officers, those being John B. Brown and Johnny L. Caudill, and Registrant 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.

10.29	Officer agreement dated November 20, 2008, between Brian S. Ramsey and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated November 21, 2008.
10.30	Officer agreement dated November 19, 2010, between Matthew D. Wesolosky and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated November 24, 2010.
10.31	Amendment to Employment Agreement dated November 17, 2016, between Glenn R. Jennings and Registrant is incorporated herein by reference to Exhibit 10.2 to Registrant's Form 8-K (File No. 000-08788) dated November 17, 2016.
10.32	Amendment to Officer Agreement, dated November 17, 2016, between John B. Brown and Registrant is incorporated herein by reference to Exhibit 10.4 to Registrant’s Form 8-K (File No. 000-08788) dated November 17, 2016.
10.33	Amendment to Officer Agreement, dated November 17, 2016, between Johnny L. Caudill and Registrant is incorporated herein by reference to Exhibit 10.6 to Registrant’s Form 8-K (File No. 000-08788) dated November 17, 2016.
10.34	Amendment to Officer Agreement, dated November 17, 2016, between Brian S. Ramsey and Registrant is incorporated herein by reference to Exhibit 10.8 to Registrant’s Form 8-K (File No. 000-08788) dated November 17, 2016.
10.35	Amendment to Officer Agreement, dated November 17, 2016, between Matthew D. Wesolosky and Registrant is incorporated herein by reference to Exhibit 10.10 to Registrant’s Form 8-K (File No. 000-08788) dated November 17, 2016.
10.36	Supplemental retirement benefit agreement and trust agreement between Glenn R. Jennings and Registrant is incorporated herein by reference to Exhibit 10(a) to Registrant's Form 8-K (File No. 000-08788) dated February 25, 2005.
10.37	Registrant's Amended and Restated Dividend Reinvestment and Stock Purchase Plan, dated November 17, 2005 is incorporated herein by reference to Exhibit 99(b) to Registrant's S-3D (Reg. No. 333-130301) dated December 14, 2005 and Post-Effective Amendment No. 1 to Registrant's S-3 (Reg. No. 333-130301) dated August 29, 2012.
10.38	Registrant's Incentive Compensation Plan, dated January 1, 2008 is incorporated herein by reference to Exhibit 4.1 to Registrant's S-8 (Reg. No. 333-165210) dated March 4, 2010.
10.39	Notices of Performance Shares Award between five officers, those being John B. Brown, Johnny L. Caudill, Glenn R. Jennings, Brian S. Ramsey and Matthew D. Wesolosky, and Registrant are incorporated herein by reference to Exhibit 10.1, 10.2, 10.3, 10.4 and 10.5, respectively, of Registrant's Form 8-K (File No. 000-08788) dated August 21, 2013.
10.40	Form of Notice of Performance Shares Award is incorporated herein by reference to Exhibit 10.03 to Registrant's Form 10-Q (File No. 000-08788) for the period ended September 30, 2015.
10.41	Agreement and Plan of Merger with PNG Companies, LLC and Drake Merger Sub, Inc. dated February 20, 2017 is incorporated herein by reference to Exhibit 2.1 to Registrant's Form 8-K (File No. 000-08788) dated February 21, 2017.
12	Computation of the Consolidated Ratio of Earnings to Fixed Charges.
21	Subsidiaries of the Registrant.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101	Attached as Exhibit 101 to this Annual Report are the following documents formatted in extensible business reporting language (XBRL):		
	(i)	Document and Entity Information;	
	(ii)	Consolidated Statements of Income for the years ended June 30, 2017, 2016 and 2015;	
	(iii)	Consolidated Statements of Cash Flows for the years ended June 30, 2017, 2016 and 2015;	
	(iv)	Consolidated Balance Sheets as of June 30, 2017 and 2016;	
	(v)	Consolidated Statements of Changes in Shareholders' Equity for the years ended June 30, 2017, 2016 and 2015;	
	(vii)	Schedule II – Valuation and Qualifying Accounts for the years ended June 30, 2017, 2016 and 2015.	

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 1st day of September, 2017.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings

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

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	September 1, 2017

(ii) Principal Financial Officer:

/s/John B. Brown (John B. Brown)	Chief Operating Officer, Treasurer and Secretary	September 1, 2017

(iii) Principal Accounting Officer:

/s/Matthew D. Wesolosky (Matthew D. Wesolosky)	Vice President - Controller	September 1, 2017

(iv) A Majority of the Board of Directors:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	September 1, 2017
/s/Linda K. Breathitt (Linda K. Breathitt)	Director	September 1, 2017
/s/Jacob P. Cline, III (Jacob P. Cline, III)	Director	September 1, 2017
/s/Sandra C. Gray (Sandra C. Gray)	Director	September 1, 2017
/s/Edward J. Holmes (Edward J. Holmes)	Director	September 1, 2017
/s/Michael J. Kistner (Michael J. Kistner)	Director	September 1, 2017
/s/Fred N. Parker (Fred N. Parker)	Director	September 1, 2017
/s/Rodney L. Short (Rodney L. Short)	Director	September 1, 2017
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	September 1, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2017 and 2016, and the related consolidated statements of income, changes in shareholders' equity, and cash flows for each of the three years in the period ended June 30, 2017. Our audits also included the financial statement schedule listed in the Index at Item 8. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2017, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 18 to the financial statements, the Company entered into a Merger Agreement with People's Natural Gas and Drake Merger Sub Inc., a new wholly-owned subsidiary of People's Natural Gas.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2017, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated September 1, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio

September 1, 2017

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Year Ended June 30,	2017	2016	2015
Operating Revenues			
Regulated revenues	$ 41,795,560	$ 41,242,094	$ 52,681,120
Non-regulated revenues	27,044,609	22,888,126	33,507,118
Total operating revenues	$ 68,840,169	$ 64,130,220	$ 86,188,238
Operating Expenses			
Regulated purchased natural gas	$ 12,561,849	$ 11,704,178	$ 22,728,766
Non-regulated purchased natural gas	19,980,989	17,621,069	26,713,424
Operation and maintenance	15,988,178	13,989,510	14,608,835
Depreciation and amortization	6,415,660	6,416,221	6,377,743
Taxes other than income taxes	2,889,977	2,965,250	2,795,609
Total operating expenses	$ 57,836,653	$ 52,696,228	$ 73,224,377
Operating Income	$ 11,003,516	$ 11,433,992	$ 12,963,861
Other Income	$ 205,826	$ 4,124	$ 25,097
Interest Charges			
Interest on long-term debt	$ 2,181,324	$ 2,245,224	$ 2,309,124
Other interest expense	54,062	52,533	51,538
Amortization of debt expense	227,000	233,500	240,000
Total interest charges	$ 2,462,386	$ 2,531,257	$ 2,600,662
Net Income Before Income Taxes	$ 8,746,956	$ 8,906,859	$ 10,388,296
Income Tax Expense	3,230,613	3,377,481	3,892,215
Net Income	$ 5,516,343	$ 5,529,378	$ 6,496,081
Earnings Per Common Share (Note 11)			
Basic and Diluted	$ .77	$ .78	$ .92
Dividends Declared Per Common Share	$ 1.0375	$ .82	$ .80

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

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows

For the Year Ended June 30,	2017	2016	2015
Cash Flows From Operating Activities			
Net income	$ 5,516,343	$ 5,529,378	$ 6,496,081
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	6,642,660	6,649,721	6,617,743
Deferred income taxes and investment tax credits	1,346,242	1,193,793	1,449,471
Change in cash surrender value of officer's life insurance	(51,071)	6,198	(19,036)
Share-based compensation	292,174	452,230	1,095,051
Excess tax deficiency from share-based compensation	42,603	(5,508)	9,249
(Increase) decrease in assets			
Accounts receivable	(1,335,920)	1,091,517	871,270
Natural gas in storage	(2,152,990)	1,344,242	2,491,337
Deferred natural gas cost	(1,423,973)	(674,077)	724,923
Materials and supplies	(112,827)	(4,549)	(12,578)
Prepayments	1,437,116	(1,226,279)	(363,263)
Other assets	(283,540)	(288,867)	225,771
Increase (decrease) in liabilities			
Accounts payable	2,207,356	(1,181,356)	(1,135,821)
Accrued taxes	(47,140)	106,856	(80,925)
Asset retirement obligations	(59,085)	(85,068)	375,073
Other liabilities	(1,765,233)	1,832,112	20,658
Net cash provided by operating activities	$ 10,252,715	$ 14,740,343	$ 18,765,004
Cash Flows From Investing Activities			
Capital expenditures	$ (8,725,635)	$ (6,302,666)	$ (9,010,876)
Proceeds from sale of property, plant and equipment	265,239	275,397	161,311
Other	(60,000)	(60,000)	(60,000)
Net cash used in investing activities	$ (8,520,396)	$ (6,087,269)	$ (8,909,565)

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

Delta Natural Gas Company, Inc.

Consolidated Statements of Cash Flows (continued)

For the Year Ended June 30,	2017	2016	2015
Cash Flows From Financing Activities			
Dividends on common shares	$ (5,913,888)	$ (5,822,259)	$ (5,639,791)
Issuance of common shares	619,532	614,518	532,712
Payment of minimum tax withholdings on share-based compensation	(266,005)	(263,044)	—
Repayment of long-term debt	(1,500,000)	(1,500,000)	(1,500,000)
Borrowings on bank line of credit	—	—	126,430
Repayment of bank line of credit	—	—	(126,430)
Net cash used in financing activities	$ (7,060,361)	$ (6,970,785)	$ (6,607,079)
Net (Decrease) Increase in Cash and Cash Equivalents	$ (5,328,042)	$ 1,682,289	$ 3,248,360
Cash and Cash Equivalents, Beginning of Year	18,606,567	16,924,278	13,675,918
Cash and Cash Equivalents, End of Year	$ 13,278,525	$ 18,606,567	$ 16,924,278
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	$ 2,240,428	$ 2,298,228	$ 2,369,078
Income taxes (net of refunds)	$ 2,281,475	$ 2,064,005	$ 3,312,944
Significant non-cash transactions			
Accrued capital expenditures	$ 374,469	$ 157,808	$ 207,169
Accrued dividends on common shares	$ 1,480,130	$ —	$ —

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

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets

As of June 30,	2017	2016
Assets		
Current Assets		
Cash and cash equivalents	$ 13,278,525	$ 18,606,567
Accounts receivable, less accumulated allowances for doubtful accounts of $172,000 and $301,000 in 2017 and 2016, respectively	6,201,732	4,741,595
Natural gas in storage, at average cost (Note 1)	5,442,910	3,289,920
Deferred natural gas costs (Notes 1 and 14)	2,098,050	674,077
Materials and supplies, at average cost	676,919	544,342
Prepayments	3,217,770	3,051,665
Total current assets	$ 30,915,906	$ 30,908,166
Property, Plant and Equipment	$ 249,611,353	$ 241,833,771
Less - Accumulated provision for depreciation	(109,804,512)	(104,192,898)
Net property, plant and equipment	$ 139,806,841	$ 137,640,873
Other Assets		
Cash surrender value of life insurance (face amount of $957,000 and $954,000 in 2017 and 2016, respectively)	$ 466,056	$ 414,985
Prepaid Pension (Note 6)	2,113,785	—
Regulatory assets (Note 1)	15,435,233	18,881,126
Other non-current assets	1,219,106	1,033,979
Total other assets	$ 19,234,180	$ 20,330,090
Total assets	$ 189,956,927	$ 188,879,129

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

Delta Natural Gas Company, Inc.

Consolidated Balance Sheets (continued)

As of June 30,	2017	2016
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 8,110,424	$ 4,200,298
Current portion of long-term debt (Note 10)	1,500,000	1,500,000
Accrued taxes	1,537,535	1,584,675
Customers' deposits	616,661	618,137
Accrued interest on debt	106,783	111,825
Accrued vacation	750,994	756,138
Other liabilities	665,551	585,342
Total current liabilities	$ 13,287,948	$ 9,356,415
Long-Term Debt (Notes 1 and 10)	$ 48,929,196	$ 50,422,796
Long-Term Liabilities		
Deferred income taxes (Note 5)	$ 44,815,170	$ 43,405,098
Regulatory liabilities (Note 1)	1,135,362	1,138,141
Accrued Pension (Note 6)	—	1,833,780
Asset retirement obligations (Note 4)	4,030,786	3,917,585
Other long-term liabilities	1,263,470	1,078,345
Total long-term liabilities	$ 51,244,788	$ 51,372,949
Commitments and Contingencies (Note 13)		
Total liabilities	$ 113,461,932	$ 111,152,160
Shareholders' Equity		
Common shares ($1.00 par value), 20,000,000 shares authorized; 7,133,148 and 7,087,762 shares outstanding at June 30, 2017 and June 30, 2016, respectively	$ 7,133,148	$ 7,087,762
Premium on common shares	50,072,857	49,472,542
Retained earnings	19,288,990	21,166,665
Total shareholders' equity	$ 76,494,995	$ 77,726,969
Total liabilities and shareholders' equity	$ 189,956,927	$ 188,879,129

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

Delta Natural Gas Company, Inc.

Consolidated Statements of Changes in Shareholders' Equity

	Year Ended June 30, 2017			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 7,087,762	$ 49,472,542	$ 21,166,665	$ 77,726,969
Net income	—	—	5,516,343	5,516,343
Issuance of common shares	22,682	596,850	—	619,532
Issuance of common shares under the incentive compensation plan, net of cancellations	22,704	(288,709)	—	(266,005)
Share-based compensation expense	—	292,174	—	292,174
Dividends on common shares	—	—	(7,394,018)	(7,394,018)
Balance, end of year	$ 7,133,148	$ 50,072,857	$ 19,288,990	$ 76,494,995

	Year Ended June 30, 2016			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 7,026,500	$ 48,735,608	$ 21,459,546	$ 77,221,654
Net income	—	—	5,529,378	5,529,378
Issuance of common shares	28,437	586,081	—	614,518
Issuance of common shares under the incentive compensation plan, net of cancellations	32,825	(295,869)	—	(263,044)
Share-based compensation expense	—	452,230	—	452,230
Tax benefit from share-based compensation	—	(5,508)	—	(5,508)
Dividends on common shares	—	—	(5,822,259)	(5,822,259)
Balance, end of year	$ 7,087,762	$ 49,472,542	$ 21,166,665	$ 77,726,969

	Year Ended June 30, 2015			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,942,758	$ 47,182,338	$ 20,603,256	$ 74,728,352
Net income	—	—	6,496,081	6,496,081
Issuance of common shares	26,412	506,300	—	532,712
Issuance of common shares under the incentive compensation plan	57,330	385,251	—	442,581
Share-based compensation expense	—	652,470	—	652,470
Tax benefit from share-based compensation	—	9,249	—	9,249
Dividends on common shares	—	—	(5,639,791)	(5,639,791)
Balance, end of year	$ 7,026,500	$ 48,735,608	$ 21,459,546	$ 77,221,654

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

Principles of Consolidation

Delta Natural Gas Company, Inc. ("Delta" or "the Company") distributes or transports natural gas to approximately 36,000 customers. Our distribution and transportation systems are located in central and southeastern Kentucky and we own and operate an underground storage field in southeastern Kentucky. We transport natural gas to our industrial customers who purchase their natural gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system and extract liquids from natural gas in our storage field and our pipeline systems that are sold at market prices. We have three wholly-owned subsidiaries. Delta Resources, Inc. buys natural gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys natural gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates natural gas production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

On February 20, 2017, we entered into an Agreement and Plan of Merger ("Merger Agreement") with PNG Companies, LLC ("PNG"), hereinafter referred to as the "Merger". For further information, see Note 18 of the Notes to Consolidated Financial Statements.

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.

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.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at original cost, which includes materials, labor, labor related costs and an allocation of general and administrative costs. A betterment or replacement of a unit of property is accounted for as an addition of utility plant. Construction work in progress has been included in the rate base for determining customer rates, and therefore an allowance for funds used during construction has not been recorded. The cost of regulated plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, less salvage value, is charged to the accumulated provision for depreciation.

Property, plant and equipment is comprised of the following major classes of assets:

($000)	2017	2016
Regulated segment		
Distribution, transmission and storage	219,477	214,660
General, miscellaneous and intangibles	23,578	23,145
Construction work in progress	3,902	1,422
Total regulated segment	246,957	239,227
Non-regulated segment	2,654	2,607
Total property, plant and equipment	249,611	241,834

All expenditures for maintenance and repairs of units of property are charged to the appropriate maintenance expense accounts in the month incurred.

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 2.7% of average depreciable plant for 2017, and 2.8% for 2016 and 2015.

As approved by the Kentucky Public Service Commission, we accrue asset removal costs for certain types of property through depreciation expense with a corresponding increase to regulatory liabilities on the Consolidated Balance Sheets. When this depreciable utility plant and equipment is retired any related removal costs incurred are charged against the regulatory liability.

Our pipe replacement program tariff allows us to adjust our regulated rates annually to earn a return on capital incurred subsequent to our last rate case which are associated with the replacement of pipe and related facilities. The pipe replacement program is designed to additionally recover the costs associated with the mandatory retirement or relocation of facilities.

Impairment of Long-Lived Assets

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. In the opinion of management, our long-lived assets are appropriately valued in the accompanying consolidated financial statements. There were no impairments of long-lived assets during 2017, 2016 or 2015.

Natural Gas In Storage

We operate a natural gas underground storage field that we utilize to inject and store natural gas during the non-heating season, and we then withdraw natural gas during the heating season to meet our customers' needs. The potential exists for differences between actual volumes stored versus our perpetual records primarily due to differences in measurement of injections and withdrawals or the risks of natural gas escaping from the field. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the natural gas inventory carried in our perpetual inventory records. The periodic analysis of the storage field data utilizes trends in the underlying data and can require multiple periods of observation to determine if differences exist. The analysis can result in adjustments to our perpetual inventory records. The natural gas in storage inventory is recorded at average cost.

Regulated Revenues

We bill our regulated sales of natural gas at tariff rates approved by the Kentucky Public Service Commission. Our customers are billed on a monthly basis; however, the billing cycle for certain classes of customers do not necessarily coincide with the calendar month-end. For these customers, we apply the unbilled method of accounting, where we estimate and accrue revenues applicable to customers, but not yet billed. The related natural gas costs are charged to expense. At the end of each month, natural gas service which has been rendered from the date the customer's meter was last read to the month-end is unbilled. Unbilled revenues are included in accounts receivable and unbilled natural gas costs are included in deferred natural gas costs on the accompanying Consolidated Balance Sheets. Unbilled amounts include the following:

(000)	2017	2016
Unbilled revenues ($)	1,653	1,452
Unbilled natural gas costs ($)	445	319
Unbilled volumes (Mcf)	70	63

We record on-system transportation services in the period in which we transport natural gas to the end-use customer within our system. On-system transportation customers receive their natural gas supply from third-party shippers delivering natural gas into Delta's system. We bill on-system transportation services at tariff rates, as approved by the Kentucky Public Service Commission, which include both fixed monthly charges and volumetric rates. Delta Resources utilizes Delta's on-system transportation service and Delta recognizes revenue from Delta Resources at tariff rates, which eliminates upon consolidation.

We record off-system transportation services in the period in which we transport natural gas to an interstate pipeline on behalf of third-party shippers delivering natural gas into Delta's system. We bill off-system transportation services at tariff rates, as approved by the Kentucky Public Service Commission, which are volumetric rates. Delgasco utilizes Delta's off-system transportation service and Delta recognizes revenue from Delgasco at tariff rates, which eliminates upon consolidation.

The daily volumes of natural gas delivered from third-party shippers supplying our transportation customers rarely equal the daily volumes billed to our customers, resulting in periodic transportation imbalances. These imbalances are short-term in duration, and Delta monitors the activity and regularly notifies the shippers when they have an imbalance. Transportation imbalances in turn create imbalances of the natural gas supply on Delta's system, thus requiring Delta to purchase either more or less volumes of natural gas to meet our customers' natural gas requirements, and they are included on the Consolidated Balance Sheets in either accounts payable or prepayments, respectively. Consistent with the regulatory treatment for our natural gas cost recovery tariff (as further discussed in Note 14 of the Notes to Consolidated Financial Statements), imbalances do not impact our results of operations, as the net impact of the imbalances offset against the regulatory asset/liability related to our natural gas cost recovery tariff.

Non-Regulated Revenues

Delta Resources enters into contracts whereby it is obligated to supply one-hundred percent of its customers' natural gas requirements at either fixed or index-based rates. Delta Resources recognizes revenue in the period in which actual metered volumes are delivered to the customer. Delta Resources utilizes Delta's on-system transportation service and records such transportation expenses at tariff rates that eliminate upon consolidation.

Delgasco enters into contracts to deliver fixed quantities of natural gas to its customers at either fixed or index-based rates. Delgasco recognizes revenue based upon the period in which the customer takes possession of the natural gas. Delgasco utilizes Delta's off-system transportation service and records such transportation expenses at tariff rates that eliminate upon consolidation.

Enpro produces natural gas which supplies a portion of Delgasco's natural gas requirements and recognizes the sale of natural gas in the period in which Delgasco takes possession of the natural gas. Revenues and related natural gas costs between Enpro and Delgasco are both within the non-regulated segment and eliminate upon consolidation.

We recognize revenue from natural gas liquids in the period in which the customer takes possession of the natural gas liquids. Factors that affect revenue from the sale of natural gas liquids include the hydrocarbon content of the liquids, the market price for natural gas liquids and the volumes of natural gas liquids sold.

Regulated Purchased Natural Gas Expense

Our regulated natural gas rates include a natural gas cost recovery tariff approved by the Kentucky Public Service Commission which provides for a dollar-tracker that matches revenues and natural gas costs and provides eventual dollar-for-dollar recovery of all natural gas costs incurred by the regulated segment and recovery of the uncollectible natural gas cost portion of bad debt expense. We expense natural gas costs based on the amount of natural gas costs recovered through revenue. Any differences between actual natural gas costs and those natural gas costs billed are deferred and reflected in the computation of future billings to customers using the natural gas cost recovery mechanism.

Excise Taxes

Delta collects certain excise taxes levied by state or local governments from our customers. These taxes are accounted for on a net basis and therefore are not included as revenues in the accompanying Consolidated Statements of Income.

Accounts Receivable / Allowance for Doubtful Accounts

We record an allowance for doubtful accounts to reflect the expected net realizable value of accounts receivable. Accounts receivable are charged off when deemed to be uncollectible or when turned over to a collection agency to pursue.

Rate Regulated Basis of Accounting

We account for our regulated segment in accordance with applicable regulatory guidance. 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 non-regulated enterprise. When this results, costs are deferred as assets on the Consolidated Balance Sheets ("regulatory assets") and recorded as expenses when such amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for current collection in rates of costs that are expected to be incurred in the future ("regulatory liabilities"). The amounts recorded as regulatory assets and regulatory liabilities are as follows:

($000)	2017	2016
Regulatory assets		
Current assets		
Deferred natural gas costs	2,098	674
Other assets		
Conservation/efficiency program expenses	258	243
Loss on extinguishment of debt	2,468	2,689
Asset retirement obligations	5,640	5,121
Accrued pension	7,069	10,828
Total other assets	15,435	18,881
Total regulatory assets	17,533	19,555
Regulatory liabilities		
Long-term liabilities		
Accrued cost of removal on long-lived assets	549	487
Regulatory liability for deferred income taxes	586	651
Total regulatory liabilities	1,135	1,138

All of our regulatory assets and liabilities have been approved for recovery by the Kentucky Public Service Commission and are currently being recovered or refunded through our regulated natural gas rates. In addition, the unrecovered balance of the loss on extinguishment of debt is included in rate base and, therefore, earns a return. The weighted average recovery period of the other regulatory assets which are not earning a return is 28 years.

Derivatives

Certain of our natural gas purchase and sale contracts qualify as derivatives. All such contracts have been designated as normal purchases and sales and as such are accounted for under the accrual basis and are not recorded at fair value in the accompanying consolidated financial statements.

Marketable Securities

We have a supplemental retirement benefit agreement with Glenn R. Jennings, our Chairman of the Board, President and Chief Executive Officer, that is a non-qualified deferred compensation plan. The agreement establishes an irrevocable rabbi trust, in which the assets of the trust are earmarked to pay benefits under the agreement. We have recognized a liability related to the obligation to pay these benefits to Mr. Jennings. We make discretionary contributions to the trust in order to fund the related deferred compensation liability.

The assets of the trust consist of exchange traded securities and exchange traded mutual funds and are classified as trading securities. The assets are recorded at fair value on the Consolidated Balance Sheets based on observable market prices from active markets. Net realized and unrealized gains and losses are included in earnings each period to effectively offset the corresponding earnings impact associated with the change in the fair value of the deferred compensation liability to which the assets relate.

Fair Value

Fair value is defined as the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. Fair value focuses on an exit price, which is the price that would be received by us to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability.

We determine fair value based on the following fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

- Level 1 - Observable inputs consisting of quoted prices in active markets for identical assets or liabilities;
- Level 2 - Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3 - Unobservable inputs which require the reporting entity to develop its own assumptions.

Although accounting standards permit entities to elect to measure many financial instruments and certain other items at fair value, we do not currently have any financial assets or financial liabilities for which this provision has been elected. However, in the future, we may elect to measure certain financial instruments at fair value in accordance with these standards.

(2) Accounting Pronouncements

Recently Issued Pronouncements

In May, 2014, the Financial Accounting Standards Board issued guidance revising the principles and standards for revenue recognition. The guidance creates a framework for recognizing revenue to improve comparability of revenue recognition practices across entities and industries focusing on when a customer obtains control of goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity recognizes revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments. Entities will generally be required to make more estimates and use more judgment under the new standard. The guidance is effective for our quarter ending September 30, 2018.

As of June 30, 2017, we are evaluating our sources of revenue and are assessing the effect that the new guidance will have on our financial position, results of operations and cash flows. The conclusion of our assessment is contingent, in part, upon the completion of deliberations currently in progress by our industry, notably in connection with efforts to produce an accounting guide intended to be developed by the American Institute of Certified Public Accountants. In association with this undertaking, the American Institute of Certified Public Accountants formed a number of industry task forces, including a Power & Utilities Task Force (“Task Force”).

Currently, the industry is working with the Task Force to address several items including 1) the evaluation of collectability from customers if a utility has regulatory mechanisms to help assure recovery of uncollected accounts from ratepayers; 2) the accounting for funds received from third parties to partially or fully reimburse the cost of construction of an asset and 3) the accounting for alternative revenue programs, such as performance-based ratemaking. Existing alternative revenue program guidance, though excluded by the Financial Accounting Standards Board in updating specific guidance associated with revenue from contracts with customers, was continued without substantial modification. It will require separate presentation of such revenues (subject to the above-noted deliberations) in the statement of comprehensive income, effective at the same time that updated guidance associated with revenue from contracts with customers becomes effective.

Currently, a timeline for the resolution of these deliberations has not been established. Additionally, we are actively working with our peers in the rate-regulated natural gas industry to determine the accounting treatment for several other issues that are not expected to be addressed by the Task Force. Given the uncertainty with respect to the conclusions that might arise from these deliberations, we are currently unable to determine the effect the new guidance will have on our financial position, results of operations, cash flows, internal controls or the transition method we will utilize to adopt the new guidance.

In July, 2015, the Financial Accounting Standards Board issued guidance simplifying the measurement of inventory. The guidance requires inventory to be measured at the lower of cost or net realizable value. The guidance, effective for our quarter ending September 30, 2017, is not expected to have a material impact on our results of operations, financial position and cash flows.

In January, 2016, the Financial Accounting Standards Board issued guidance to improve the recognition, measurement, presentation and disclosure of financial instruments. The improvements include guidance on estimating fair value for financial instruments measured at amortized cost on the balance sheet, the classification of financial assets and liabilities on the balance sheet and reduced disclosure for the fair value of financial instruments recognized on the balance sheet at amortized cost. The guidance, effective for our quarter ending September 30, 2018, is not expected to have a material impact on our results of operations, financial position, cash flows and disclosures.

In February, 2016, the Financial Accounting Standards Board issued guidance revising the principles and standards for recognizing leases. The guidance requires a lessee to recognize on the statement of financial position a liability for the lease payments and a right-of-use asset representing the lessee's right to use the underlying asset for the lease term. The recognition and measurement of lease expenses have not significantly changed from previous guidance. The guidance is effective for our quarter ending September 30, 2018 and we are evaluating the impact the guidance is expected to have on our results of operations, financial position, cash flows and disclosures.

In March, 2017, the Financial Accounting Standards Board issued guidance to improve the recognition and presentation of net periodic pension cost. The guidance requires employers who sponsor defined benefit pension plans to disaggregate the service cost component of net periodic benefit cost from the other components of net periodic benefit cost in the income statement. The guidance also allows only the service cost component to be eligible for capitalization, which is a departure from current accounting guidance where all components of net periodic benefit cost are eligible for capitalization. The guidance is effective for our quarter ending September 30, 2018 and we are evaluating the impact the guidance is expected to have on our results of operations, financial position, cash flows, disclosures and internal controls.

Recently Adopted Pronouncements

In March, 2016, the Financial Accounting Standards Board issued guidance simplifying the accounting and disclosure requirements for share-based compensation, including income tax consequences, classification of the awards as equity or liability and classification on the statement of cash flows. The guidance is effective for our quarter ending September 30, 2017; however, we have elected early adoption.

The guidance changed the accounting for excess tax benefits and deficiencies, where previously the difference in compensation cost recognized for financial reporting purposes versus the deduction on the corporate tax return was recognized as additional paid-in capital to the extent the cumulative tax benefits exceeded tax deficiencies. Effective July 1, 2016, on a prospective basis, we began recognizing the effect of vested awards as discrete items in the period in which they occur with excess tax benefits and deficiencies recognized in the Consolidated Statements of Income as an adjustment to income tax expense. We do not have any previously unrecognized excess tax benefits which require a cumulative effect adjustment upon adoption. The guidance also requires the classification of excess tax benefits and deficiencies as an operating activity on the Consolidated Statements of Cash Flows, which has been adopted retrospectively and resulted in an immaterial reclassification between financing activities and operating activities on the Consolidated Statements of Cash Flows.

Entities may elect an accounting policy for forfeitures where they can either continue the current method of recognizing forfeitures based on the number of awards expected to vest or as forfeitures occur. We have elected to recognize forfeitures as they occur. The adoption of this accounting policy did not result in a cumulative effect adjustment.

The threshold increased for an award to qualify for equity classification where shares are redeemed to meet statutory withholding obligations. Shares can now be redeemed up to the maximum statutory tax rates in the applicable jurisdiction, rather than the minimum statutory tax rates. The adoption of this guidance did not result in a change in classification of the award requiring a cumulative effect adjustment.

(3) Fair Value Measurements

Our financial assets and liabilities measured at fair value on a recurring basis consist of the assets of our supplemental retirement benefit trust, which are included in other non-current assets on the Consolidated Balance Sheets. Contributions to the trust are presented in other investing activities on the Consolidated Statements of Cash Flows. The assets of the trust consist of exchange traded securities and exchange traded mutual funds. The securities and mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the fair value hierarchy. The trust assets are as follows:

($000)	2017	2016
Money market	48	44
U.S. equity securities	539	435
Foreign equity funds	246	168
U.S. fixed income funds	269	223
Foreign fixed income funds	23	19
Absolute return strategy mutual funds	94	145
Total trust assets	1,219	1,034

The carrying amounts of our other financial instruments including cash equivalents, accounts receivable, notes receivable and accounts payable approximate their fair value. The fair value of the assets in our defined benefit retirement plan are disclosed in Note 6 of the Notes to Consolidated Financial Statements.

Our Series A Notes, presented as current portion of long-term debt and long-term debt on the Consolidated Balance Sheets, are stated at historical cost, net of unamortized debt issuance costs. The fair value of our long-term debt is based on the expected future cash flows of the debt discounted using a credit adjusted risk-free rate. The credit adjusted risk-free rate for our 4.26% Series A Notes is the estimated cost to borrow a debt instrument with the same terms from a private lender at the measurement date. The fair value of our long-term debt is categorized as Level 3 in the fair value hierarchy.

	2017		2016	
($000)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
4.26% Series A Notes	50,429	52,978	51,923	55,324

(4) Asset Retirement Obligations

Legal obligations

As of June 30, 2017 and 2016, we have accrued liabilities and related assets, net of accumulated depreciation, relative to the legal obligation to retire certain natural gas wells, storage tanks, mains and services. For asset retirement obligations related to regulated assets, accretion of the liability and depreciation of the asset retirement costs are recorded as regulatory assets, pursuant to regulatory accounting standards, as we recover the cost of removing our regulated assets through our depreciation rates.

The following is a summary of our asset retirement obligations as shown on the accompanying Consolidated Balance Sheets:

($000)	2017	2016
Balance, beginning of year	3,918	3,796
Liabilities incurred	38	28
Liabilities settled	(357)	(266)
Accretion	280	271
Revisions in estimated cash flows	152	89
Balance, end of year	4,031	3,918

We have an additional asset retirement obligation related to the retirement of wells located at our underground natural gas storage facility. Since we expect to utilize the storage facility as long as we provide natural gas to our customers, we have determined the underlying asset has an indeterminate life. Therefore, we have not recorded a liability associated with the cost to retire the wells.

Non-legal obligations

In accordance with established regulatory practices, we accrue costs of removal on long-lived assets through depreciation expense to the extent recovery of such costs is granted by the Kentucky Public Service Commission even though such costs do not represent legal obligations. In accordance with regulatory accounting standards, $549,000 and $487,000 of such accrued cost of removal was recorded as a regulatory liability on the accompanying Consolidated Balance Sheets as of June 30, 2017 and 2016, respectively.

(5) 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 capitalization thresholds for tax reporting purposes versus financial reporting purposes, differences in recognition of purchased natural gas costs and certain accruals which are not currently deductible for income tax purposes. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The net deferred income tax liability is presented as non-current in deferred income taxes on the accompanying Consolidated Balance Sheets. The temporary differences which gave rise to the net accumulated deferred income tax liability for the periods are as follows:

($000)	2017	2016
Deferred Tax Liabilities		
Deferred natural gas cost	(796)	(256)
Prepaid expenses	(339)	(392)
Accelerated depreciation	(39,603)	(38,862)
Prepaid pension	(982)	—
Regulatory assets - asset retirement obligations	(1,078)	(981)
Regulatory assets - loss on extinguishment of debt	(937)	(1,021)
Regulatory assets - unrecognized accrued pension	(2,684)	(4,110)
Regulatory liabilities	(837)	(837)
Other	(1,082)	(1,084)
Total deferred tax liabilities	(48,338)	(47,543)
Deferred Tax Assets		
Bad debt reserve	65	114
Accrued pension	—	516
Accrued employee benefits	783	875
Asset retirement obligations	1,468	1,425
Regulatory liabilities	1,060	1,084
Section 263(a) capitalized costs	58	32
Other	89	92
Total deferred tax assets	3,523	4,138
Net accumulated deferred income tax liability	(44,815)	(43,405)

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

($000)	2017	2016	2015
Current			
Federal	1,605	1,817	1,950
State	279	366	493
Total	1,884	2,183	2,443
Deferred	1,347	1,194	1,449
Income tax expense	3,231	3,377	3,892

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

(%)	2017	2016	2015
Statutory federal income tax rate	34.0	34.0	34.0
State income taxes, net of federal benefit	4.0	4.0	4.0
Amortization of investment tax credits	—	(0.1)	(0.1)
Other differences, net	(1.1)	—	(0.4)
Effective income tax rate	36.9	37.9	37.5

We recognize the income tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The liability for unrecognized tax benefits expected to be recognized within the next twelve months has partially offset our prepaid income taxes and been presented in prepayments on the Consolidated Balance Sheets. The liability for unrecognized tax benefits not expected to be recognized within the next twelve months has been presented in other long-term liabilities on the Consolidated Balance Sheets. Interest and penalties on tax uncertainties are classified in income tax expense in the Consolidated Statements of Income.

As of June 30, 2017 and 2016, we did not have any unrecognized tax positions, which, if recognized, would impact the effective tax rate.

We file income tax returns in federal and Kentucky jurisdictions. Tax years previous to June 30, 2014 and June 30, 2013 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(6) Employee Benefit Plans

Defined Benefit Retirement Plan

We have a trusteed, noncontributory, defined benefit retirement plan covering all eligible employees hired prior to May 9, 2008. Retirement income is based on the number of years of service and annual rates of compensation. The Company has historically made annual contributions to fund the plan adequately.

Generally accepted accounting principles ("GAAP") require employers who sponsor defined benefit retirement plans to recognize the funded status of a defined benefit retirement plan on the balance sheet and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. However, regulatory accounting standards provide that regulated entities can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current cost-of-service ratemaking in Kentucky allows recovery of net periodic benefit cost as determined under GAAP. The Kentucky Public Service Commission has been clear and consistent with its historical treatment of such rate recovery; therefore, we have recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the defined benefit retirement plan that is expected to be recognized in future net periodic benefit cost. The regulatory asset is adjusted annually as prior service cost and actuarial losses are recognized in net periodic benefit cost.

Our obligations and the funded status of our plan, measured at June 30, 2017 and 2016, respectively, are as follows:

($000)	2017	2016
Change in Benefit Obligation		
Benefit obligation at beginning of year	31,572	28,838
Service cost	1,021	1,004
Interest cost	1,053	1,157
Actuarial (gain) loss	(1,317)	1,517
Benefits paid	(721)	(944)
Benefit obligation at end of year	31,608	31,572
Change in Plan Assets		
Fair value of plan assets at beginning of year	29,738	30,984
Actual return on plan assets	3,205	(802)
Employer contributions	1,500	500
Benefits paid	(721)	(944)
Fair value of plan assets at end of year	33,722	29,738
Recognized Amounts		
Projected benefit obligation	(31,608)	(31,572)
Plan assets at fair value	33,722	29,738
Funded status	2,114	(1,834)
Net amount recognized as prepaid (accrued) pension on the Consolidated Balance Sheets	2,114	(1,834)
Items Not Yet Recognized as a Component of Net Periodic Benefit Cost		
Prior service cost	(57)	(144)
Accumulated net losses	7,126	10,972
Amounts recognized as regulatory assets	7,069	10,828

The accumulated benefit obligation was $28,320,000 and $28,124,000 for 2017 and 2016, respectively.

($000)	2017	2016	2015
Components of Net Periodic Benefit Cost			
Service cost	1,021	1,004	990
Interest cost	1,053	1,157	1,056
Expected return on plan assets	(1,623)	(1,636)	(1,711)
Amortization of unrecognized net loss	947	373	244
Amortization of prior service cost	(86)	(86)	(86)
Net periodic benefit cost	1,312	812	493

(%)	2017	2016	2015
Weighted-Average Assumptions Used to Determine Benefit Obligations			
Discount rate	3.75	3.50	4.25
Rate of compensation increase	4.0	4.0	4.0
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	3.5	4.25	4.25
Expected long-term return on plan assets	5.5	5.5	6.0
Rate of compensation increase	4.0	4.0	4.0

Plan Assets

Our target investment allocations have been developed using an asset allocation model which weighs risk versus return of various investment indices to create a target asset allocation to maximize return subject to a moderate amount of portfolio risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolios contain a diversified blend of equity and fixed income investments. Our target investment allocations are approximately 65% equity investments and 35% fixed income investments. Our equity investment target allocations are heavily weighted toward domestic equity securities, with allocations to domestic real estate securities and foreign equity securities for the purposes of diversification. Fixed income securities primarily include U.S. government obligations and corporate debt securities. For additional diversification, we invest in absolute return strategy mutual funds, which include both equity and fixed income securities, with the objective of providing a return greater than inflation. The plan has amended its investment policy to allow for liability driven investments which, over time, will match a portion of the plan's liability with the underlying assets. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocations as appropriate.

The assets of the plan are comprised of investments in individual securities and mutual funds.

	Target	Actual Allocations	
(%)	Allocations	2017	2016
Asset Class			
Cash and cash equivalents	3	4	3
Equity Securities			
U.S. equity securities	44	34	35
Foreign equity securities	21	17	17
	65	51	52
Fixed Income Securities			
U. S. fixed income security	13	23	21
Foreign fixed income security	2	4	2
	15	27	23
Other Securities			
Absolute return strategy mutual funds	7	10	14
Real estate investment trusts	10	8	8
	17	18	22
	100	100	100

Individual exchange traded equity securities, exchange traded mutual funds and treasury securities are categorized as Level 1 in the fair value hierarchy as the fair value of the investments is determined based on the quoted market price of each investment. Mutual funds are categorized based on their primary investment strategy. The respective level within the fair value hierarchy is determined as described in Note 1 of the Notes to Consolidated Financial Statements. Corporate bonds, municipal bonds and U.S. agency securities are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt (maturity and coupon rate) supported by observable transactions and are categorized as Level 2 in the fair value hierarchy. The following represents the fair value of the plan assets:

($000)	2017	Level 1	Level 2	Level 3
Asset Class				
Cash	1,169	1,169	—	—
Equity Securities				
U.S. equity securities	11,293	11,293	—	—
Foreign equity securities	5,658	5,658	—	—
	16,951	16,951	—	—
Fixed Income Securities				
U.S. treasury securities	1,301	1,301	—	—
U.S. corporate bonds	1,664	—	1,664	—
High yield funds	4,418	4,418	—	—
Foreign bond funds	1,326	1,326	—	—
Other	636	—	636	—
	9,345	7,045	2,300	—
Other				
Absolute return strategy mutual funds	3,517	3,517	—	—
Real estate investment trusts and master-limited partnerships	2,740	2,153	587	—
	6,257	5,670	587	—
Total investments at fair value	33,722	30,835	2,887	—

($000)	2016	Level 1	Level 2	Level 3
Asset Class				
Cash	807	807	—	—
Equity Securities				
U.S. equity securities	10,355	10,355	—	—
Foreign equity securities	4,952	4,952	—	—
	15,307	15,307	—	—
Fixed Income Securities				
U.S. treasury securities	387	387	—	—
U.S. corporate bonds	990	—	990	—
High yield funds	4,397	4,397	—	—
Foreign bond funds	624	624	—	—
Other	680	—	680	—
	7,078	5,408	1,670	—
Other				
Absolute return strategy mutual funds	4,300	4,300	—	—
Real estate investment trusts and master-limited partnerships	2,246	2,084	162	—
	6,546	6,384	162	—
Total investments at fair value	29,738	27,906	1,832	—

We determined the expected long-term rate of return for plan assets with input from plan actuaries and investment consultants based upon many factors including asset allocations, historical asset returns and expected future market conditions. The discount rates used by the Company for valuing pension liabilities are based on a review of high-quality corporate bond yields with maturities approximating the remaining life of the projected benefit obligations.

We made $1,500,000 in discretionary contributions to the defined benefit retirement plan in fiscal 2017. In August, 2017, we made a $500,000 discretionary contribution to the defined benefit retirement plan.

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

($000)	
2018	3,211
2019	1,699
2020	1,281
2021	1,176
2022	1,375
2023 - 2027	9,035

Effective May 9, 2008, any employees hired on and after that date were not eligible to participate in our defined benefit retirement plan. Freezing the defined benefit retirement plan for new entrants did not impact the level of benefits for existing participants.

We do not provide postretirement or postemployment benefits other than the defined benefit retirement plan for retired employees and the supplemental retirement agreement described below.

Employee Savings Plan

We have an employee savings plan under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 4% of the employee's annual compensation. Employees hired after May 9, 2008, who are not eligible to participate in the defined benefit retirement plan, annually receive an additional 4% non-elective contribution into their employee savings plan account. Company contributions are discretionary and subject to change with approval from our Board of Directors. For 2017, 2016 and 2015, our employee savings plan expense was $396,000, $379,000 and $359,000, respectively.

Supplemental Retirement Agreement

We sponsor a nonqualified defined contribution supplemental retirement agreement for Glenn R. Jennings, Delta's Chairman of the Board, President and Chief Executive Officer. Delta makes discretionary contributions into an irrevocable trust until Mr. Jennings' retirement. At retirement, the trustee will make annual payments of $100,000 to Mr. Jennings until the trust is depleted. For 2017, 2016 and 2015, Delta contributed $60,000 each year to the trust. As of June 30, 2017 and 2016, the irrevocable trust assets are $1,219,000 and $1,034,000, respectively. These amounts are included in other non-current assets on the accompanying Consolidated Balance Sheets. Liabilities, in corresponding amounts, are included in other long-term liabilities on the accompanying Consolidated Balance Sheets.

(7) Dividend Reinvestment and Stock Purchase Plan

Our Dividend Reinvestment and Stock Purchase Plan (“Reinvestment Plan”) provides that shareholders of record can reinvest dividends and also make limited additional investments of up to $50,000 per year in shares of common stock of the Company. Under the Reinvestment Plan we issued 22,682, 28,437 and 26,412 shares in 2017, 2016 and 2015, respectively. We registered 400,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2017 there were approximately 15,000 shares available for issuance. The Reinvestment Plan was terminated effective June 30, 2017.

(8) Risk Management and Derivative Instruments

To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our natural gas supply through a combination of requirements contracts with no minimum purchase obligations, monthly spot purchase contracts and forward purchase contracts. We mitigate price risk related to the sale of natural gas by efforts to balance supply and demand. For our regulated segment, we utilize requirements contracts, spot purchase contracts and our underground storage to meet our regulated customers' natural gas requirements, all of which have minimal price risk because we are permitted to pass these natural gas costs on to our regulated customers through our natural gas cost recovery tariff. None of our natural gas contracts are accounted for using the fair value method of accounting. While some of our natural gas purchase contracts and natural gas sales contracts meet the definition of a derivative, we have designated these contracts as normal purchases and normal sales.

(9) Notes Payable

The current bank line of credit with Branch Banking and Trust Company permits borrowings up to $40,000,000, all of which was available as of June 30, 2017 and June 30, 2016. During 2017 and 2016, we did not have any borrowing on our bank line of credit. The bank line of credit extends through June 30, 2019, but will be terminated upon the closing of the Merger. The interest rate on the used line of credit is the London Interbank Offered Rate plus 1.075%. The annual cost of the unused bank line of credit is 0.125%. Our most restrictive covenants are discussed in Note 10 of the Notes to Consolidated Financial Statements.

(10) Long-Term Debt

Our Series A Notes are unsecured, bear interest at a rate of 4.26% per annum, which is payable quarterly, and mature on December 20, 2031. We are required to make an annual $1,500,000 principal payment on the Series A Notes each December. The following table summarizes the contractual maturities of our Series A Notes by fiscal year:

($000)	
2018	1,500
2019	1,500
2020	1,500
2021	1,500
Thereafter	44,500
Total maturing debt	50,500

Any additional prepayment of principal by the Company may be subject to a prepayment premium which varies depending on the yields of United States Treasury securities with a maturity equal to the remaining average life of the Series A Notes.

We amortize debt issuance expenses over the life of the related debt using the effective interest method. As of June 30, 2017 and 2016, $71,000 and $77,000 of debt issuance costs, respectively, were reflected as an adjustment to the carrying amount of our long-term debt on the accompanying Consolidated Balance Sheets. As of June 30, 2017 and 2016, we had a loss on extinguishment of debt of $2,468,000 and $2,689,000, respectively, which has been deferred as a regulatory asset and is being amortized over the term of the debt, as further discussed in Note 1 of the Notes to Consolidated Financial Statements.

With our bank line of credit and Series A Notes, we have agreed to certain financial and other covenants. Noncompliance with these covenants can make the obligations immediately due and payable. Our financial covenants include covenants related to our tangible net worth, total debt to capitalization ratio and fixed charge ratio. Additionally, the Company may not pay aggregate dividends on its capital stock (plus amounts paid in redemption of its capital stock) in excess of the sum of $15,000,000 plus the Company's cumulative earnings after September 30, 2011 adjusted for certain unusual or non-recurring items. We believe we were in compliance with the financial covenants under our bank line of credit and 4.26% Series A Notes for all periods presented in the Consolidated Financial Statements.

Furthermore, the agreement governing our 4.26% Series A Notes contains a cross-default provision which provides that we will be in default under the 4.26% Series A Notes if we are in default on any other outstanding indebtedness that exceeds $2,500,000. Similarly, the loan agreement governing the bank line of credit contains a cross-default provision which provides that we will be in default under the bank line of credit if we are in default under our 4.26% Series A Notes and fail to cure the default within ten days of notice from the bank.

(11) Earnings per Share

The following table sets forth the computation of basic and diluted earnings per common share:

	2017	2016	2015
Numerator - Basic and Diluted ($000)			
Net income	5,516	5,529	6,496
Dividends declared	(7,394)	(5,822)	(5,640)
Undistributed earnings (loss) (a)	(1,878)	(293)	856
Allocated to common shares:			
Undistributed earnings (loss) (a)	(1,878)	(293)	851
Dividends declared (b)	7,391	5,798	5,609
Earnings allocated to common shares	5,513	5,505	6,460
Denominator - Basic and Diluted			
Weighted average common shares (c)	7,118,170	7,066,925	7,002,694
Earnings per Common Share - Basic and Diluted ($)	0.77	0.78	0.92

(a) Percentage allocated to common shares:

	2017	2016	2015
Weighted average:			
Common shares outstanding	7,118,170	7,066,925	7,002,694
Unvested participating shares outstanding (d)	—	—	45,500
Total	7,118,170	7,066,925	7,048,194
Percentage allocated to common shares	100.0%	100.0%	99.4%
Undistributed earnings (loss) ($000)	(1,878)	(293)	856
Allocated to common shares	(1,878)	(293)	851

(b) Represents dividends paid on common shares, exclusive of unvested participating shares.

(c) Under our Incentive Compensation Plan, recipients of performance share awards receive unvested non-participating shares, as further discussed in Note 16 of the Notes to Consolidated Financial Statements. Unvested non-participating shares become dilutive in the interim quarter-end in which the performance objective is met. If the performance objective continues to be met through the end of the performance period, these shares become unvested participating shares as of the fiscal year-end, as further discussed below in Note (c). The weighted average number of unvested non-participating shares outstanding during a period is included in the diluted earnings per common share calculation using the treasury stock method, unless the effect of including such shares would be antidilutive. There were no unvested non-participating shares outstanding as of June 30, 2017, 2016 and 2015.

(d) Certain awards under our shareholder approved incentive compensation plan, as further discussed in Note 16 of the Notes to Consolidated Financial Statements, provide the recipients of the awards all the rights of a shareholder of Delta including the right to dividends declared on common shares. Any unvested shares which are participating in dividends are considered participating securities and are included in our computation of basic and diluted earnings per share using the two-class method unless the effect of including such shares would be antidilutive. As of June 30, 2017 and 2016, there were 4,000 and 28,000 participating shares outstanding, respectively, which were excluded from the computation of earnings allocated to common shares, as the holders of the unvested participating shares do not have a contractual obligation to share in losses. There were no antidilutive shares in 2015. There were 4,000, 28,000 and 65,000 unvested participating shares outstanding as of June 30, 2017, 2016 and 2015, respectively.

(12) Operating Leases

We have no non-cancellable operating leases. Our operating leases relate primarily to well and compressor station site leases and are cancellable at our option. Rental expense under operating leases was $68,000, $78,000 and $69,000 for the years ended June 30, 2017, 2016 and 2015, respectively.

(13) Commitments and Contingencies

We have entered into an employment agreement with our Chairman of the Board, President and Chief Executive Officer and change in control agreements with our other four officers. The agreements expire or may be terminated at various times. The agreements provide for continuing monthly payments and the continuation of specified benefits over varying periods following defined changes in ownership of the Company if the officer is either terminated without cause during the term of the agreement or the officer terminates his employment because the officer cannot in good faith effectively carry out his duties. In the event all of these agreements were exercised in the form of lump sum payments, approximately $4.7 million of wages would be paid in addition to continuation of specified benefits for up to five years. Additionally, the agreements provide for a reimbursement of excise taxes levied on such payments and a gross-up of income taxes attributable to the reimbursement. If all agreements were exercised by the officers, based on the $30.50 per share price offered by PNG, approximately $14.7 million would be paid, which includes wages, benefits, unvested shares awarded under our Incentive Compensation Plan and any tax gross-ups.

Jacob Halberstam, et al v. Delta Natural Gas Company, Inc., et al. Clark Circuit Court, Kentucky. The plaintiff filed this complaint on April 13, 2017, on behalf of himself and all Delta shareholders against Delta, its directors and PNG and Merger Sub. The plaintiff alleges that the defendants breached fiduciary duties to the Delta shareholders and aided and abetted breaches of fiduciary duties in connection with the Merger Agreement, under the terms of which Delta would be merged with and into Merger Sub, with Delta being the surviving corporation and becoming a wholly owned subsidiary of PNG. The plaintiff seeks to enjoin the consummation of the proposed transaction or, if the proposed transaction is closed, damages from Delta's directors.

Paul Parshall, et al. v. Delta Natural Gas Company, Inc., et al, United States District Court for the Eastern District of Kentucky at Lexington. The plaintiff filed this complaint on April 28, 2017, on behalf of himself and all Delta shareholders against Delta, its directors, PNG, Merger Sub and SteelRiver Infrastructure Fund North America, LP. The plaintiff alleges that the defendants violated Sections 14(a) and 20(a) of the Securities Exchange Act of 1934 in connection with the Merger Agreement. The complaint has been dismissed without prejudice.

Judy Cole, et al. v. Delta Natural Gas Company, Inc., et al. Clark Circuit Court, Kentucky. The plaintiff filed this complaint on May 5, 2017, on behalf of herself and all Delta shareholders against Delta and its directors. The plaintiff alleges that the defendants breached fiduciary duties to the Delta shareholders in connection with the Merger Agreement and the proxy statement sent to Delta shareholders describing the transaction. The plaintiff seeks to enjoin the consummation of the proposed transaction.

Counsel for Delta, counsel for PNG, Merger Sub and SteelRiver Infrastructure Fund North America, LP and counsel for the plaintiffs in the three lawsuits described above have entered a confidential memorandum of understanding dated May 25, 2017, under the terms of which the litigation will be settled, subject to court approval, with Delta making additional disclosures to its shareholders, which has been done. It is anticipated that the plaintiffs will seek an order from the Clark Circuit Court requiring Delta to pay attorneys' fees and expenses of the plaintiffs. The amount of the anticipated fee request and any amount of settlement is unknown. During 2017, no expense has been recognized related to the fee request or settlement in the Consolidated Statement of Income. Delta is insured for such litigation, subject to a $1 million deductible.

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

In connection with the Merger, we retained Tudor Pickering, Holt & Co. Advisors, LLC ("TPH") to act as financial advisors in connection with the transaction contemplated by the Merger Agreement and $1,853,000 is payable to TPH upon closing of the Merger. Additionally, upon closing of the Merger, Delta is required to purchase runoff insurance coverage for six years which will cost an estimated $158,000. During 2017, none of these amounts have been recognized as an expense in the Consolidated Statement of Income.

We have entered into forward purchase agreements for a portion of our non-regulated segment's natural gas purchases through June, 2019 . The agreements require us to purchase minimum amounts of natural gas throughout the term of the agreements.

The agreements are established in the normal course of business to ensure adequate natural gas supply to meet our non-regulated customers' natural gas requirements. The agreements have aggregate minimum purchase obligations of $350,000 and $199,000 for our fiscal years ending June 30, 2018 and 2019, respectively.

(14) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services, which includes approval of our regulated rates and tariffs. We monitor our need to file requests with them for a general rate increase for our natural gas distribution and transportation services. The Kentucky Public Service Commission has historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of natural gas costs, and a reasonable rate of return on our rate base. Rate base consists primarily of our regulated segment's property, plant and equipment, natural gas in storage and unamortized debt expense offset by accumulated depreciation and certain deferred income taxes. Our regulated rates were most recently adjusted in our 2010 rate case and became effective in October, 2010. We do not have any matters before the Kentucky Public Service Commission which would have a material impact on our results of operations, financial position or cash flows.

Our pipe replacement program tariff allows us to adjust rates annually to earn a return on capital expenditures incurred subsequent to our last rate case which are associated with the replacement of pipe and related facilities. The pipe replacement program is designed to additionally recover the costs associated with the mandatory retirement or relocation of facilities.

Our natural gas cost recovery tariff permits us to adjust the rates charged to our customers to reflect changes in our natural gas supply costs and any bad debt expense related to natural gas cost. Although we are not required to file a general rate case to adjust rates pursuant to the natural gas cost recovery tariff, we are required to make quarterly filings with the Kentucky Public Service Commission. Under and over-recovered natural gas costs are collected or refunded through adjustments to customer bills beginning three months after the end of the quarter in which the actual natural gas costs were incurred.

Our weather normalization tariff provides for the adjustment of our rates to residential and small non-residential customers to reflect variations from thirty- year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

Additionally, we have a conservation and efficiency program tariff for our residential customers, which allows us to adjust our rates for activities performed through the program. Through this program, we perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers' interests by reimbursing us for the gross margins on lost sales due to operating the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in seven of the cities we serve, and we continue to operate under the conditions of expired franchises in fifteen other cities we serve. In the other cities and areas we serve, the areas served do not have governmental organizations authorized to grant franchises or the city governments do not require a franchise. We attempt to acquire or reacquire franchises whenever feasible. Without a franchise, a city could require us to cease our occupation of the streets and public grounds or prohibit us from extending our facilities into any new area of that city. To date, the absence of a franchise has not adversely affected our operations.

On March 17, 2017, we and PNG filed a joint application with the Kentucky Public Service Commission seeking regulatory approval of the Merger, as further discussed in Note 18 of the Notes to Consolidated Financial Statements. On August 15, 2017, the Kentucky Public Service Commission issued an order granting unconditional approval of the Merger and we anticipate closing to occur by September 30, 2017.

(15) Segment Information

Our Company has two reportable segments: a regulated segment and a non-regulated segment. Our regulated segment includes our natural gas distribution and transportation services, which are regulated by the Kentucky Public Service Commission. Our non-regulated segment includes our natural gas marking activities and the sales of natural gas liquids. The non-regulated segment produces a portion of the natural gas it markets to its customers. The division of these segments into separate revenue generating components is based upon regulation, products and services. Both segments operate in the single geographic area of central and southeastern Kentucky. Our chief operating decision maker is our Chief Executive Officer. We evaluate performance based on net income of the respective segment.

In our non-regulated segment, two customers each provided more than 5% of our operating revenues for 2017. Our largest customer provided approximately $15,889,000, $11,555,000 and $17,852,000 of non-regulated revenues during 2017, 2016 and 2015, respectively. Our second largest customer provided approximately $4,744,000, $5,656,000 and $7,127,000 of non-regulated revenues during 2017, 2016 and 2015, respectively. There is no assurance that revenues from these customers will continue at these levels.

Our regulated segment purchased approximately 99% of its natural gas from CenterPoint Energy Services and Midwest Energy Services in 2017, 2016 and 2015.

Our non-regulated segment purchased approximately 95% of its natural gas from CenterPoint Energy Services and Midwest Energy Services in 2017. We purchased approximately 99% of our natural gas from CenterPoint Energy Services and Midwest Energy Services in 2016 and 2015.

The reportable segments follow the accounting policies as described in the Summary of Significant Accounting Policies in Note 1 of the Notes to Consolidated Financial Statements. Intersegment revenues and expenses represent the natural gas transportation costs from the regulated segment to the non-regulated segment at our tariff rates. Operating expenses, taxes and interest are allocated to the non-regulated segment.

Segment information is shown in the following table:

($000)	2017	2016	2015
Operating Revenues			
Regulated			
External customers	41,795	41,242	52,681
Intersegment	3,446	3,591	3,869
Total Regulated	45,241	44,833	56,550
Non-regulated			
External customers	27,045	22,888	33,507
Eliminations for intersegment	(3,446)	(3,591)	(3,869)
Total operating revenues	68,840	64,130	86,188
Operating Expenses			
Regulated			
Purchased natural gas	12,562	11,704	22,729
Depreciation and amortization	6,323	6,328	6,293
Other	18,240	16,033	15,819
Total regulated	37,125	34,065	44,841
Non-regulated			
Purchased natural gas	19,981	17,621	26,713
Depreciation and amortization	93	88	84
Other	4,084	4,513	5,455
Total non-regulated	24,158	22,222	32,252
Eliminations for intersegment	(3,446)	(3,591)	(3,869)
Total operating expenses	57,837	52,696	73,224
Other Income			
Regulated	206	4	25
Non-regulated	—	—	—
Total other income	206	4	25
Interest Charges			
Regulated	2,415	2,486	2,551
Non-regulated	47	45	50
Total interest charges	2,462	2,531	2,601
Income Tax Expense			
Regulated	2,153	3,238	3,553
Non-regulated	1,078	139	339
Total income tax expense	3,231	3,377	3,892
Net Income			
Regulated	3,754	4,982	5,748
Non-regulated	1,762	547	748
Total net income	5,516	5,529	6,496
Assets			
Regulated	184,843	185,634	183,482
Non-regulated	5,114	3,245	4,229
Total assets	189,957	188,879	187,711
Capital Expenditures			
Regulated	8,679	6,293	8,991
Non-regulated	47	10	20
Total capital expenditures	8,726	6,303	9,011

(16) Share-Based Compensation

We have a shareholder approved incentive compensation plan (the "Plan") that provides for compensation payable in shares of our common stock. The Plan is administered by our Corporate Governance and Compensation Committee of our Board of Directors, which has complete discretion in determining our employees, officers and outside directors who shall be eligible to participate in the Plan, as well as the type, amount, terms and conditions of each award, subject to the limitations of the Plan.

The number of shares of our common stock that may be issued pursuant to the Plan may not exceed in the aggregate 1,000,000 shares. As of June 30, 2017, approximately 751,000 shares of common stock were available for issuance under the Plan, subject to the limitations imposed by our Corporate Governance Guidelines. Shares of common stock may be available from authorized but unissued shares, shares reacquired by us or shares that we purchase in the open market. Upon vesting, the Plan allows for withholding a number of shares equal in fair value to the taxes required to satisfy statutory withholding requirements. The following table sets forth the number of shares granted by fiscal year:

	2017		2016		2015	
	Shares	Grant Date Fair Value (000's)	Shares	Grant Date Fair Value (000's)	Shares	Grant Date Fair Value (000's)
Stock Awards	9,600	$ 247	8,400	$ 169	22,000	443
Performance Shares	41,000	1,056	39,000	787	39,000	773
Total	50,600	$ 1,303	47,400	$ 956	61,000	1,216

Compensation expense for share-based compensation is recorded in the non-regulated segment in operation and maintenance expense in the Consolidated Statements of Income based on the fair value of the awards at the grant date and is amortized over the requisite service period. Fair value is the closing price of our common shares at the grant date. The grant date is the date at which our commitment to issue the share-based awards arises, which is generally when the award is approved and the terms of the awards are communicated to the employee or director. We initially recognize expense for our performance shares when it is probable that any stipulated performance criteria will be met. Forfeitures of awards are recognized as they occur. The following table sets forth our share-based compensation expense by fiscal year:

($000)	2017	2016	2015
Stock Awards	247	169	443
Performance Shares	45	283	652
Total	292	452	1,095

Stock Awards

In 2017, 2016 and 2015, common stock was awarded to Delta's outside directors as the equity component of their compensation and in 2015 common stock was additionally awarded to virtually all Delta employees. The recipients vested in the awards shortly after the awards were granted, but during the time between the grant dates and the vesting dates the shares awarded were not transferable by the holders. Once the shares were vested, the shares received under the stock awards were immediately transferable.

Performance Shares

In 2017, 2016 and 2015, performance shares were awarded to the Company's executive officers. The performance shares vest only if the performance objectives of the awards are met, which are based on the Company's earnings per common share for the fiscal year in which the performance shares are awarded, before any cash bonuses or share-based compensation. Upon satisfaction of the performance objectives, unvested shares are issued to the recipients and vest in one-third increments each August 31 subsequent to achieving the performance objectives as long as the recipients are employees throughout each such service period. Unvested shares of executive officers, while still employed by the Company, will fully vest upon them attaining the age of sixty-seven. The recipients of the awards also become vested as a result of certain events such as death or disability of the holders. The unvested shares have both dividend participation rights and voting rights during the remaining terms of the awards. Holders of performance shares may not sell, transfer or pledge their shares until the shares vest.

The performance objectives for the performance shares awarded in 2017 and 2016 were not satisfied and the awards were forfeited. Performance objectives for the performance shares awarded in 2015 were met and 4,000 of these shares remain unvested as of June 30, 2017. The Company will recognize the remaining $4,000 of expense associated with these shares in 2018.

Our performance shares have graded vesting schedules, and each separate annual vesting tranche is treated as a separate award for expense recognition. Compensation expense is amortized over the vesting period of the individual awards based on the probable outcome of meeting the performance objectives.

Since the performance condition has been satisfied for the shares granted in 2015, the holder of performance shares will have both dividend participation rights and voting rights during the remaining term of the awards. The holder becomes vested as a result of certain events such as death or disability of the holder. Subject to the satisfaction of the performance condition, the weighted average expected remaining vesting period at June 30, 2017 is 2 months.

The following summarizes the activity for performance shares:

	Performance shares	
	Number of shares	Weighted-average grant date fair value ($ per share)
Unvested shares at June 30, 2016	28,000	20.15
Granted (a)	41,000	25.75
Vested	(24,000)	20.21
Forfeited	(41,000)	25.75
Unvested shares at June 30, 2017	4,000	19.82

(a) Represents the maximum number of shares which could be issued based on achieving the performance criteria.

(17) Quarterly Financial Data (Unaudited)

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

($000, except per share amounts)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2017				
September 30	10,508	(260)	(458)	(.06)
December 31	18,937	4,534	2,444	.34
March 31	26,787	6,993	4,021	.56
June 30	12,608	(263)	(491)	(.07)
Fiscal 2016				
September 30	10,393	(133)	(524)	(.08)
December 31	16,673	3,478	1,803	.25
March 31	26,202	7,084	3,983	.56
June 30	10,861	1,004	267	.05

(18) Merger with PNG Companies, LLC

On February 20, 2017, we entered into a Merger Agreement with PNG and Drake Merger Sub Inc. ("Merger Sub"), a new wholly owned subsidiary of PNG. A special meeting of shareholders was held on June 1, 2017 where shareholders voted and approved the Merger and on August 15, 2017, the Kentucky Public Service Commission issued an order granting unconditional approval of the Merger. The Merger Agreement provides for the merger of Merger Sub with and into Delta, with Delta surviving as a wholly owned subsidiary of PNG. At the effective time of the Merger, subject to customary closing conditions, each share of Delta common stock issued and outstanding immediately prior to the closing will be converted automatically into the right to receive $30.50 in cash per share, without interest, less any applicable withholding taxes. Upon consummation of the Merger, Delta common stock will be delisted from NASDAQ and the bank line of credit will be terminated. We anticipate closing to occur by September 30, 2017.

Subsequent to closing of the Merger, a stub period dividend will be paid to Delta's shareholders of record immediately prior to closing which is a prorated quarterly dividend calculated in accordance with the terms of the Merger Agreement.

In connection with this transaction, in 2017 we incurred $1,612,000 of Merger-related expenses for costs paid to outside parties, which are reflected in operation and maintenance in the Consolidated Statement of Income. This amount does not include the cost of company personnel participating in Merger-related activities. Refer to Note 13 of the Notes to Consolidated Financial Statements for a discussion of litigation related to the Merger.

SCHEDULE II

DELTA NATURAL GAS COMPANY, INC.

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED JUNE 30, 2017, 2016 and 2015

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, 2017	$ 300,696	$ 1,240	$ 40,716	$ 170,861	$ 171,791
June 30, 2016	258,400	247,724	122,364	327,792	300,696
June 30, 2015	360,000	170,631	237,267	509,498	258,400

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

	2017	2016	2015	2014	2013
Earnings					
Net income	$ 5,516,343	$ 5,529,378	$ 6,496,081	$ 8,275,128	$ 7,200,776
Provisions for income taxes (a)	3,230,613	3,377,481	3,892,215	4,858,586	4,268,784
Fixed charges	2,485,386	2,557,257	2,623,662	2,694,187	2,770,935
Total	$11,232,342	$11,464,116	$13,011,958	$15,827,901	$14,240,495
Fixed Charges					
Interest on debt (a)	$ 2,235,386	$ 2,297,757	$ 2,360,662	$ 2,424,587	$ 2,493,135
Amortization of debt expense	227,000	233,500	240,000	246,600	253,800
One third of rental expense	23,000	26,000	23,000	23,000	24,000
Total	$ 2,485,386	$ 2,557,257	$ 2,623,662	$ 2,694,187	$ 2,770,935
Ratio of earnings to fixed charges	4.52x	4.48x	4.96x	5.87x	5.14x

(a) Interest accrued on uncertain tax positions, in accordance with Accounting Standards Codification Topic 740 - Income Taxes, is presented in income taxes on the Consolidated Statements of Income. This interest has been excluded from the determination of fixed charges.

EXHIBIT 21

Subsidiaries of the Registrant

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

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement No. 333-130301 on Form S-3 of our reports dated September 1, 2017, relating to the consolidated financial statements and financial statement schedule of Delta Natural Gas Company, Inc. and subsidiaries ("the Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2017.

/s/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio

September 1, 2017

EXHIBIT 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

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

I, Glenn R. Jennings, certify that:

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

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

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

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

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

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

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

DATE: September 1, 2017

/s/Glenn R. Jennings

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

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

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

I, John B. Brown, certify that:

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

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

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

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

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

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

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

DATE: September 1, 2017

/s/John B. Brown

John B. Brown
Chief Operating Officer, Treasurer and Secretary

Exhibit 32.1

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

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: September 1, 2017

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

Exhibit 32.2

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

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Operating Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: September 1, 2017

/s/John B. Brown

John B. Brown
Chief Operating Officer, Treasurer and Secretary