COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

PURCHASED GAS ADJUSTMENT	)	
FILING OF DELTA NATURAL	)	**CASE NO. 2018-00317**
GAS COMPANY, INC.	)	

VERIFICATION

The undersigned, **John B. Brown**, being duly sworn, deposes and states that he is President, Secretary and Treasurer of Delta Natural Gas Company, Inc. and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John B Brown

John B. Brown

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of September, 2018.

Emily P. Bennett (SEAL)
Notary Public

My Commission Expires:

6/20/20

Emily P. Bennett
Notary Public, ID No. 558362
State at Large, Kentucky
My Commission Expires on June 20, 2020

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

PURCHASED GAS ADJUSTMENT	)	
FILING OF DELTA NATURAL	)	**CASE NO. 2018-00317**
GAS COMPANY, INC.	)	

VERIFICATION

The undersigned, **Don Cartwright**, being duly sworn, deposes and states that he is Vice-President – Gas Supply of Delta Natural Gas Company, Inc. and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Don Cartwright

Don Cartwright

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of September, 2018.

Emily P. Bennett (SEAL)
Notary Public

My Commission Expires:

6/20/20

Emily P. Bennett
Notary Public, ID No. 558362
State at Large, Kentucky
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

PURCHASED GAS ADJUSTMENT	)	
FILING OF DELTA NATURAL	)	**CASE NO. 2018-00317**
GAS COMPANY, INC.	)	

VERIFICATION

The undersigned, **Jenny Lowery Croft**, being duly sworn, deposes and states that she is Manager – Employee & Regulatory Services of Delta Natural Gas Company, Inc. and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Jenny Lowery Croft

Jenny Lowery Croft

STATE OF KENTUCKY	)
	)
COUNTY OF CLARK	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of September, 2018.

Emily P. Bennett (SEAL)

Notary Public

My Commission Expires:

6/20/20

Emily P. Bennett
Notary Public, ID No. 558362
State at Large, Kentucky
My Commission Expires on June 20, 2020

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

1. Provide copies of all interstate pipeline transportation and storage contracts and tariffs utilized during the most recent year. Provide a comparison of the terms of these transportation arrangements with those that were utilized during the five previous calendar years. Explain all efforts to ensure that interstate pipeline transportation costs were and are as low as possible.

Response:

See the listing below of all interstate pipeline transportation and storage contracts and tariffs utilized during the most recent year. Copies of these contracts and tariffs are attached as indicated. The terms of these contracts and tariffs have remained unchanged during the five previous calendar years. Even though some of the contracts have been executed within the previous five calendar years, the terms of these contracts have remained unchanged during the five previous calendar years. The only tariff changes during the previous five calendar years have been ordered by FERC.

The Company is a member of a small customer group, represented by Mr. Joshua Menter of McCarter & English, LLP, which represents our interests to Interstate pipelines in an effort to keep interstate pipeline transportation costs as low as possible.

Company	Description	Exhibit
Columbia Gulf	Rate Schedule FTS-1, 2016	1-1
Columbia Gulf	FTS-1 Service Agreement No. 43827, 2015	1-2
Columbia Gulf	FTS-1 Service Agreement No. 43829, 2015	1-3
Columbia Gulf	Operational Balancing Agreement No. 60242, 2017	1-4
Columbia Gas	GTS Rate Schedule, 2016	1-5
Columbia Gas	GTS Service Agreement No. 37813, 2015	1-6
Columbia Gas	GTS Service Agreement No. 37814, 2015	1-7
Columbia Gas	GTS Service Agreement No. 37815, 2015	1-8
Texas Eastern (TETCO)	Operational Balancing Agreement, 2016	1-9
Tennessee Gas Pipeline (TGP)	Rate Schedule FT-GS Small Customer Transportation Service, 2011	1-10

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

Company	Description	Exhibit
Tennessee Gas Pipeline (TGP)	Rate Schedule FT-A Firm Transportation Service, 2013	1-11
Tennessee Gas Pipeline (TGP)	Amendment No. 2 Gas Transportation Agreement Service Package No. 2747, 1994	1-12
Tennessee Gas Pipeline (TGP)	Gas Transportation Agreement TGP Contract No. T-2747, 1993	1-13
Tennessee Gas Pipeline (TGP)	Executed FT-G, FT-A and FS Contracts, 1993	1-14
Tennessee Gas Pipeline (TGP)	Gas Transportation Service Agreements Service Package No.'s 2448, 2516, 2555, and 2747, 1995	1-15
Tennessee Gas Pipeline (TGP)	Gas Transportation Service Agreements Service Package No.'s 2448, 2516, 2555, and 2747, 1995	1-16
Tennessee Gas Pipeline (TGP)	Gas Transportation Agreement TGP Contract No. T-2448, 1993	1-17
Tennessee Gas Pipeline (TGP)	Gas Transportation Agreement TGP Contract No. T-2515, 1993	1-18
Tennessee Gas Pipeline (TGP)	Gas Transportation Agreement TGP Contract No. T-2555	1-19
Tennessee Gas Pipeline (TGP)	Gas Transportation Agreement TGP Contract No. T-2516	1-20
Tennessee Gas Pipeline (TGP)	Gas Storage Service Agreement TGP Service Package No. 2366, 1996	1-21
Tennessee Gas Pipeline (TGP)	TGP Duplicate Original Market and Production Area Contracts, 1993	1-22

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

2. Provide copies of all current contracts for commodity supply. Provide a comparison of the terms of these commodity supply arrangements with those that were utilized during the five previous calendar years. Explain all efforts to ensure that commodity gas supply costs are/were the lowest possible cost, consistent with security of supply.

Response:

See the listing below of all current contracts for commodity supply. Copies of these contracts are attached as indicated.

Company	Description	Exhibit
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Amendment to Transaction Confirmation, 2017	2-1
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Transaction Confirmation #314454 Exhibit A for Firm service on TETCO pipeline, 2011	2-2
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Amendment to Gas Sales Agreement, 2017	2-3
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Gas Sales Agreement between Delta Natural Gas Company, Inc and Woodward Marketing, LLC on Tennessee Gas Pipeline (TGP), 2000	2-4
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Amendment to Gas Sales Agreement, 2017	2-5
CenterPoint Energy Services, Inc. (formerly Atmos Energy Marketing, LLC, formerly Woodward Marketing, LLC)	Gas Sales Agreement between Delta and Woodward Marketing, LLC on Columbia Gulf and Gas pipelines, 2003	2-6
Midwest Energy Services, LLC	Base Contract for Sale and Purchase of Natural Gas, 2013	2-7

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

Company	Description	Exhibit
Midwest Energy Services, LLC	Transaction Confirmation, 2018	2-8
Vinland Energy Operations, LLC (formerly Columbia Natural Resources, Inc.)	Addendum to Contract for Gas Sales and Delivery Service Off of Gathering Facilities, 2012	2-9
Vinland Energy Operations, LLC (formerly Columbia Natural Resources, Inc.)	Contract for Gas Sales and Delivery Service Off of Gathering Facilities, 1999	2-10
Greystone, LLC	Base Contract for Sale and Purchase of Natural Gas, 2016	2-11
Greystone, LLC	Transaction Confirmation, 2017	2-12

Even though some of the contracts have been executed within the previous five calendar years, the terms of these contracts have remained unchanged during the five previous calendar years.

The terms of these transportation arrangements have remained unchanged during the five previous calendar years.

Delta Natural Gas uses a third party asset management company, Center Point Energy Service, with a strong and secure record of service to manage and supply gas in Delta's North systems.

Delta Natural Gas uses Midwest Energy to supply gas in Delta's South systems and for Canada Mountain storage requirements.

Delta Natural Gas purchases gas supply from Vinland Energy for captive farm tap customers on Vinland's gathering pipeline.

Delta Natural Gas purchases gas supply from Greystone Energy for captive farm tap customers on the Somerset Pipeline.

All terms are negotiated based on Delta's Interstate pipeline storage and the market price at the time contracts are signed.

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

3. Provide gas supply and capacity contract summaries showing significant contract terms, daily/monthly/annual entitlements, and pricing. Identify any capacity changes (renegotiated and expired agreements, de-contracting, assignment, or long-term release) that took place during the most recent year.

Response:

No contract changes were made in 2017. See below.

Company	Description	Exhibit
Tennessee Gas Pipeline (TGP)	Maximum Daily Quantities	3-1
Tennessee Gas Pipeline (TGP)	FT-A Transportation Contract No. 2747	3-2
Tennessee Gas Pipeline (TGP)	FT-A Transportation Contract No. 2747 Rate Schedule	3-3
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2448	3-4
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2448 Rate Schedule	3-5
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2516	3-6
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2516 Rate Schedule	3-7
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2555	3-8
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 2555 Rate Schedule	3-9
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 9069	3-10
Tennessee Gas Pipeline (TGP)	FT-G Transportation Contract No. 9069 Rate Schedule	3-11
Columbia Gas (TCo)	Maximum Daily Quantities	3-12
Columbia Gas (TCo)	GTS Service Agreement No. 37813	3-13
Columbia Gas (TCo)	GTS Service Agreement No. 37814	3-14

DELTA NATURAL GAS COMPANY, INC.
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RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

Company	Description	Exhibit
Columbia Gas (TCo)	GTS Service Agreement No. 37815	3-15
Columbia Gas (TCo)	GTS Service Agreement No. 37948	3-16
Columbia Gas (TCo)	GTS Service Agreement No. 37954	3-17
Columbia Gulf	Gulf Assignment Agreement No. 43827 FTS-1	3-18
Columbia Gulf	Gulf Assignment Agreement No. 43828 FTS-1	3-19
Columbia Gulf	Gulf Assignment Agreement No. 43829 FTS-1	3-20
Columbia Gas (TCo)	TCo Currently Effective Rates GTS	3-21
Columbia Gas (TCo)	TCo Retainage Percentages GTS	3-22
Columbia Gulf	Currently Effective Rates FTS-1	3-23
Columbia Gulf	Retainage Percentages FTS-1	3-24

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

4. Provide Delta's storage arrangements; state the maximum daily injection and withdrawal rates and the decline in deliverability that occurs as gas is withdrawn.

Response:

Company	Description	Exhibit
Tennessee Gas Pipeline (TGP)	Max Daily Storage Injection/ Withdrawals	4-1
Tennessee Gas Pipeline (TGP)	FS Gas Storage Contract No. 2362	4-2
Tennessee Gas Pipeline (TGP)	FS Gas Storage Contract No. 2363	4-3
Tennessee Gas Pipeline (TGP)	FS Gas Storage Contract No. 2364	4-4
Tennessee Gas Pipeline (TGP)	FS Gas Storage Contract No. 2365	4-5
Tennessee Gas Pipeline (TGP)	FS Gas Storage Contract No. 2366	4-6
Columbia Gas (TCo)	Max Daily Storage Injection/ Withdrawals	4-7
Columbia Gas (TCo)	Cumberland GTS Service Agreement No. 37813	4-8
Columbia Gas (TCo)	Cumberland GTS Service Agreement No. 37814	4-9
Columbia Gas (TCo)	Cumberland GTS Service Agreement No. 37815	4-10
Columbia Gas (TCo)	Cumberland GTS Service Agreement No. 37948	4-11
Columbia Gas (TCo)	Cumberland GTS Service Agreement No. 37954	4-12
Delta Natural Gas Co. Inc.	Canada Mountain Deliverability	4-13

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

The Company holds storage capacity on Tennessee Gas Pipeline under its FS-MA and FS-PA contracts. The injection, withdrawal, and annual volumes are listed in the attached TGP summary in Exhibits 4-1 through 4-6. There is no reduction in deliverability as storage inventory levels decline.

The Company does not have separate storage agreements on Columbia Gas Transmission's system. The Company's GTS service agreements (which replaced the Small General Service one-part rate schedule when FERC Order 636 was implemented) with Columbia Gas include a defined storage level that is an integral part of the GTS transportation service. The individual storage injection, withdrawal, and annual levels are also reflected on the attached CGT summary in Exhibits 4-7 through 4-12. There is no reduction in deliverability as storage levels decline. Neither are GTS customers subject to the ratcheting provisions required of larger storage customers on CGT.

The Company owns and operates the Canada Mountain Storage Field in Bell County, Kentucky. This field is an abandoned production field which was purchased by the Company in late 1995. The base gas level of the field is 2,200,000 Mcf. At the close of the injection season of 2017, the total level of working gas in the field was 2,863,481 Mcf, for a total field volume of 5,063,481 Mcf. The field pressure at the close of the 2017 injection season was approximately 1,010 psig. Attached as Exhibit 4-13 is a schedule showing the calculated field deliverability at various pressures.

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

5. Provide the capacity of any peaking arrangements.

Response:

The Company does not have any facilities used strictly for peak-shaving purposes, such as a propane plant or LNG facility. Peak day volumes are included in the firm pipeline and contract storage daily capacities plus the Company's own on-system storage field.

Sponsoring Witness:

Don Cartwright

6. Provide a copy of any written procedures in use by Delta for nominations and dispatching.

Response:

Delta does not have a written procedure for nominations and dispatching. However, prior to delivery of transportation gas to Delta, each on-system transportation customer or shipper is required to submit a Customer Nomination Form. This form is to be used by any shipper which is delivering gas into a meter which is operated by Delta. Please see attached copy of Customer Nomination Form. This Form must be completed and returned to Delta's Coordinator – Gas Supply prior to the applicable delivering pipeline's nomination deadline.

Delta's suppliers are responsible for submitting nominations on the interstate pipelines. Prior to the applicable pipeline's nomination deadline, Delta's Coordinator – Gas Supply will provide to its suppliers the volumes to be nominated on the interstate pipelines for the following month.

Delta's Coordinator – Gas Control is responsible for the off-system transportation nominations. Nominations are calculated monthly and the off-system transportation customer and Delta's Coordinator – Gas Supply are notified. Nominations are adjusted intra-month as necessary.

Sponsoring Witness:

Don Cartwright

7. If Delta has utilized gas marketing/trading organizations to obtain gas supplies over the last five years, indicate which organizations were so employed, gas volumes purchased, prices, terms, and current contractual arrangements between Delta and these marketing firms.

Response:

The Company did not utilize any gas marketing/trading organizations to obtain gas supplies over the last five years.

Sponsoring Witness:

Don Cartwright

8. Provide a summary of the bidding/Request for Proposal process for gas supply for the last five years, providing the original bid documents, a listing of the suppliers that were contacted, the responses to the request for bid, the evaluation process that led to the selection of a supplier, and any written procedures that exist for this activity.

Response:

The Company did not initiate any bidding/Request for Proposal for gas supply over the last five years. The Company does not have a written procedure for this activity. The margin of our commodity supply has remained unchanged with CenterPoint Energy Services, Inc., Vinland Energy Operations, LLC and Greystone LLC. The table below shows the decrease in margin with Midwest Energy Services, LLC over the last five years.

Date	Company	Margin
December, 2013	Midwest Energy Services, LLC	$.18
December, 2014	Midwest Energy Services, LLC	$.17
December, 2015	Midwest Energy Services, LLC	$.125
November, 2016	Midwest Energy Services, LLC	$.07
December, 2017	Midwest Energy Services, LLC	$.06
August, 2018	Midwest Energy Services, LLC	$.055

See Response #2 for Delta's contracts for commodity supply. Delta plans to initiate a bid process prior to the expiration of the current contracts which range from 2019 -2021.

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

9. Provide a copy of Delta's most recent gas supply plan and a written description of its gas supply planning process.

Response:

Delta uses monthly and Peak Day historical data to determine gas supply for our North System based on normal ambient temperatures. Delta submits the monthly estimated gas supply need to our asset management company who provides the supply.

Delta has developed in-house Microsoft Excel programs for its South System that we utilize for supply planning. Historical base load and heat load factors are calculated and then applied to current temperature forecasts to develop a supply plan that correspond. Canada Mountain Storage along with additional suppliers listed in Response #2 are used to ensure supply.

Delta's Strategic Plan, provided as Exhibit 14-1 in Response #14 addresses ensuring system and supply integrity (page 5), and safety (page 8).

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

10. Provide a narrative description of any supply-planning computer models currently being used by Delta, or being considered for future use.

Response:

The Company does not utilize a computer model purchased from an outside vendor for supply planning. However, we have developed in-house Microsoft Excel programs that we use for supply planning. We take the data from the Microsoft Excel peak day and annual load forecasting models described in Response #9 and develop a supply plan to correspond with it.

Sponsoring Witness:

Don Cartwright

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

11. Provide organization charts of the overall corporate organization and of the gas planning, gas purchasing, and gas operations functions. Describe any changes that have occurred in the corporate, gas planning and purchasing, and gas operations organization in the last five years, and any changes that are underway or contemplated within the next five years.

Response:

See attached Exhibit 11-1.

Brian Ramsey had been Delta's VP-Gas Supply and Transportation for several years until his retirement in November, 2017. Brian's reports were Don Cartwright, managing Gas Control Operations, Robert Cobb, managing Transmission and Storage, and Wayne Hunter, Coordinator—Gas Supply. Upon Brian's retirement, Don Cartwright, with 38 years of experience at Delta, was promoted to VP-Gas Supply and Wayne Hunter began reporting to him. Jonathan Morphew, with 31 years of experience at Delta, was promoted to VP-Operations and Robert Cobb, continuing to manage the Transmission and Storage departments, began reporting to Jonathan.

Don and Jonathan report to John Brown, who began reporting to Morgan O'Brien, the CEO of PNG, upon the retirement of Glenn Jennings on September 21, 2018.

No changes are currently underway or contemplated within the next five years.

Sponsoring Witness:

John B. Brown

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

12. Provide job descriptions of the personnel working in the gas planning, gas purchasing, and gas operations functions.

Response:

The Vice President – Gas Supply, Coordinator – Gas Supply, Coordinator – Gas Control, and Gas Controllers perform the gas planning, gas purchasing, and gas operations functions for Delta. Job descriptions for these positions are attached to this response as Exhibit 12-1.

Sponsoring Witness:

Jenny Lowery Croft

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

13. Provide copies of reports or internal audits or reviews of any aspect of the supply function conducted within the last five years. Include reports prepared by Delta and outside auditors.

Response:

There were no audits or reviews performed that specifically focused on any aspect of the gas supply function within the last five years; however, as Delta was a publicly held company until September 2017, an integrated audit was performed by Deloitte & Touche LLP each of the last five years. Integrated audits include expressing an opinion on internal controls. Delta's system of internal controls includes controls over the gas supply function. See attached for copies of the 2013-2017 10-K filings, which include Deloitte's opinions.

Sponsoring Witness:

Jenny Lowery Croft

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 2018-00317

RESPONSES TO DATA REQUEST
ORDER DATED JULY 5, 2018

14. Provide a copy of Delta's strategic plan with primary emphasis on gas procurement, transmission, delivery, expansion and inclusive of any significant related capital expenditures.

Response:

See attached Exhibit 14-1 addressing the ensuring of system and supply integrity (page 5), and safety (page 8).

Sponsoring Witness:

John B. Brown

RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE

1. AVAILABILITY

(a) Service under this Rate Schedule is available from Columbia Gulf Transmission, LLC (Transporter) to any Shipper, provided that (i) Transporter has sufficient facilities and transportation capacity available to receive gas from or on behalf of Shipper and deliver gas to or for Shipper; (ii) Transporter has awarded capacity to Shipper under the provisions of Section 4 of the General Terms and Conditions; (iii) Shipper has executed an FTS-1 Service Agreement with Transporter; and (iv) Shipper complies with the provisions of this Rate Schedule and with all other applicable provisions of this Tariff.

2. APPLICABILITY AND CHARACTER OF SERVICE

(a) Zone of Service. Service under this Rate Schedule is applicable to any Shipper who delivers gas to and receives gas from Transporter from Transporter's Market Zone.

(b) Character of Service. The transportation service provided under this Rate Schedule shall be performed under Subpart B or G of Part 284 of the Commission's Regulations. Subject to the limitations set forth below, Transporter under this Rate Schedule shall receive scheduled quantities from or on behalf of Shipper and shall deliver thermally equivalent scheduled quantities, less Retainage, to or for Shipper. Such service shall be provided on a firm basis and shall apply to all gas transported by Transporter for Shipper under this Rate Schedule, up to the Transportation Demand set forth in the Shipper's FTS-1 Service Agreement.

(c) Receipt and Delivery Obligations. Transporter shall not be obligated on any Day to accept gas in excess of the lesser of: (i) Shipper's Scheduled Daily Receipt Quantity; or (ii) Shipper's Transportation Demand plus Retainage. Transporter shall also not be obligated on any Day to deliver more gas to Shipper than the lesser of: (i) Shipper's Transportation Demand; (ii) the quantity of gas Transporter receives for Shipper, less Retainage; or (iii) Shipper's Scheduled Daily Delivery Quantity. For the purpose of balancing any imbalances in Shipper's account Shipper may deliver or take quantities in excess of the above limitations in accordance with the provisions of Section 6 and Section 7 of the General Terms and Conditions.

(d) Segmentation.

(1) General. Under normal operating conditions, a Shipper under this Rate Schedule may segment its transportation capacity between both primary and secondary physical receipt and delivery points. For purposes of this section, the phrase "normal operating conditions" means those situations in which Transporter is not required to: (i) construct or install new facilities in order to accommodate a capacity segmentation request from a Shipper under this Rate Schedule; or (ii) operate or modify Transporter's

existing facilities in a manner consistent with the current design and operation of such facilities in order to accommodate a capacity segmentation request from a Shipper.

(2) Eligible Points. Virtual aggregation points under Rate Schedule AS, supply pooling points under Rate Schedule IPP, and virtual scheduling points that represent physical receipt or delivery points are eligible receipt or delivery points for segmentation purposes.

(3) Limitations. A Shipper may not use its segmented primary or secondary physical points in such a way that its total nomination within any segment or at any primary or secondary points exceeds its original Transportation Demand in that segment or at such point(s). Notwithstanding the foregoing, Shipper may segment its capacity to consist of south-north and north-south flows up to original Transportation Demand to the same point at the same time, subject to the scheduling and allocation provisions of Section 7 of the General Terms and Conditions. Segmented nominations in the opposite direction of the original capacity to the same point will be provided on a secondary basis. Shipper shall not be permitted to segment its transportation capacity under this Rate Schedule if such segmentation would limit Transporter's ability to provide firm service to other Shippers or in situations where transportation capacity is not available in particular segments or at primary or secondary points.

(4) Requests for Segmentation. Requests for segmentation of transportation capacity under this Rate Schedule must be submitted by Shipper and Transporter shall evaluate such requests to determine if capacity segmentation can be permitted as requested by Shipper. Transporter reserves the right to evaluate and disallow segmentation on a case-by-case basis for those situations that are not operationally feasible and not already described in this section. Transporter shall review all properly submitted requests for segmentation within ten (10) days but will use reasonable efforts to accommodate a Shipper if a request for segmentation is made less than ten (10) days before the desired effective date. Disallowance of segmentation requests will be made on a non-discriminatory basis. Within ten business days, Transporter will post on its EBB the reason for denial of any request for capacity segmentation that is due to Transporter's determination that the request is not operationally feasible.

(e) Capacity Release. Service rights under an FTS-1 Service Agreement may be released and assigned in accordance with Section 14 of the General Terms and Conditions. Service to an assignee under any such release and assignment shall be subject to the terms and conditions set forth in this Rate Schedule and in the General Terms and Conditions. Under normal operating conditions, a Shipper that releases its service under an FTS-1 Service Agreement may release transportation capacity on any segment between primary physical receipt and delivery points, and secondary physical receipt and delivery points at which it does not have primary receipt and delivery rights under its FTS-1 Service Agreement. A Releasor may not re-release a released segment until the Releasor either recalls the released segment or the released segment reverts to the Releasor at the end of the release term. Replacement Shippers that desire to re-release a released segment may release transportation capacity within their acquired capacity segment and to any points within the zone for which the Shipper pays. The sum of capacity released in any segment cannot exceed the Releasor's original Transportation Demand.

(f) Termination Dates for Specified Volumes. Transporter and Shipper may mutually agree on a not unduly discriminatory basis to (i) different termination dates for specified volumes of Transportation Demand within the same Service Agreement and/or (ii) combine Service Agreements under this Rate Schedule into a single Service Agreement under this Rate Schedule with different termination dates for specified volumes of Transportation Demand. Transporter and Shipper may mutually agree to combine Service Agreements only to the extent that the individual Service Agreement's rates, terms, and conditions can be distinctly maintained and will not be altered by the combination. For Service Agreement(s) executed in accordance with this section, each of the varying termination dates and associated volumes of Transportation Demand will be set forth on a separate Appendix A to the Service Agreement applicable to service pursuant to this Rate Schedule. Each component with a different termination date for a specified volume of Transportation Demand within the same Service Agreement and reflected in a separate Appendix A will be regarded as a single Service Agreement for purposes of Shipper's exercise of any right of first refusal under the provisions of Section 4 of the General Terms and Conditions of Transporter's Tariff. In the event of a constraint or other occurrence that precludes combined nominations or allocations, Transporter may advise Shippers under such combined Service Agreements that capacity must be nominated separately and is subject to separate allocation pursuant to the terms of each separate Appendix A of the Service Agreement. Each Appendix A of the combined Service Agreements will be identified by its original contract number or such other identification convention determined to be applicable by Transporter.

(g) Increase / Decrease of Transportation Demand. Appendix A of the Service Agreement will contain a stated Transportation Demand, provided however, that the Transporter and Shipper may mutually agree on a not unduly discriminatory basis to allow a Shipper to structure Transportation Demand to increase and decrease at pre-determined intervals on pre-determined dates. Transporter and Shipper will utilize the fill-in-the-blanks in Appendix A to specify the Begin Date, End Date, and volumes of Transportation Demand associated with each pre-determined interval. For purposes of Shipper's exercise of any right of first refusal under the provisions of Section 4 of the General Terms and Conditions of Transporter's Tariff, Shipper shall have the right to retain the Transportation Demand in effect on the termination date of Shipper's Service Agreement.

(h) If the Transportation Demand is to be provided under one Service Agreement (Multi-Party Service Agreement) for multiple Shippers ("Principals") that have designated a party to act as administrator on their behalf ("Administrator"), Principals and Administrator shall provide notice of such to Transporter in the form of an executed Administrator Agreement, posted on Transporter's Electronic Bulletin Board, between Principals and Administrator. Principals and Administrator also shall provide sufficient information to verify:

(1) that Principals collectively meet the "Shipper must have title" requirement as set forth in Section 23 (Warranty of Title to Gas) of the General Terms and Conditions;

(2) that once the Administrator executes the Multi-Party Service Agreement, each Principal agrees that it is jointly and severally liable for all of the obligations of Shipper under the Multi-Party Service Agreement;

(3) that Principals agree that they shall be treated collectively as one Shipper for nomination, allocation and billing purposes; and

(4) that Principals collectively satisfy the requirements to request service, including the credit requirements under the provisions outlined in Section 3 (Requests for Service) and Section 9.5 (Creditworthiness of Shipper) of the General Terms and Conditions. Administrator will provide Transporter information on Principals to determine that Principals collectively satisfy the requirements to request service.

Administrator shall be permitted to unilaterally amend the Multi-Party Service Agreement to remove a Principal or to add a Principal that satisfies the requirements of Section 3 (Request for Service) and Section 9.5 (Creditworthiness of Shipper) of the General Terms and Conditions and of this Section 2(h). No such amendment shall be binding on Transporter prior to the date that notice thereof has been given to Transporter. In order for Principals to replace the Administrator of the Multi-Party Service Agreement, Principals must provide Transporter with notice in the form of a new, executed Administrator Agreement between Principals and the new Administrator. Transporter will require the new Administrator to enter a new Multi-Party Service Agreement on behalf of the Principals.

3. RATE

(a) The charges to be paid by Shipper shall be no higher than the applicable total effective maximum charges and no lower than the applicable total effective minimum charges set forth in this Tariff, unless otherwise mutually agreed by Transporter and Shipper. For all service rendered under this Rate Schedule, Shipper each month shall pay Transporter the charges set forth below, unless otherwise mutually agreed to by Transporter and Shipper:

(1) Reservation Charge: The maximum Reservation Charge for each Month, assessed on each Dth of Transportation Demand specified in Shipper's FTS-1 Service Agreement.

(2) Commodity Charge: The maximum Commodity Charge per Dth of gas actually delivered each Day during the Month to or for the account of Shipper.

(3) Overrun Charge: The applicable Overrun Charge per Dth of gas nominated by Shipper, scheduled by Transporter and actually delivered on any Day during the Month in excess of Shipper's Transportation Demand.

(4) Surcharges: The surcharges applicable to this Rate Schedule.

(b) The charges and surcharges described above are subject to adjustment in accordance with the procedures set forth in the General Terms and Conditions.

(c) The Reservation Charge shall apply as of the date firm transportation service is deemed to commence by the terms of Shipper's FTS-1 Service Agreement.

(d) In addition to the charges and applicable surcharges, Transporter shall retain from the gas tendered for transportation the effective Retainage percentage set forth in this Tariff. That Retainage percentage shall be subject to adjustment in accordance with Section 32 (Transportation Retainage Adjustment) of the General Terms and Conditions

4. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions are applicable to this Rate Schedule and are hereby made a part hereof.

Service Agreement No. 43827
Revision No. 3

FTS-1 SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 29 day of October, 2015, by and between COLUMBIA GULF TRANSMISSION, LLC ("Transporter") and DELTA NATURAL GAS COMPANY, INC., STANTON DIVISION ("Shipper").

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. Transporter shall perform and Shipper shall receive the service in accordance with the provisions of the effective FTS-1 Rate Schedule and applicable General Terms and Conditions of Transporter's FERC Gas Tariff, Third Revised Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission herein contained. The maximum obligations of Transporter to deliver gas hereunder to or for Shipper, the designation of the points of delivery at which Transporter shall deliver or cause gas to be delivered to or for Shipper, and the points of receipt at which the Shipper shall deliver or cause gas to be delivered, are specified in Appendix A, as the same may be amended from time to time by agreement between Shipper and Transporter, or in accordance with the rules and regulations of the Commission.

Section 2. Term. Service under this Agreement shall commence as of November 1, 2015, and shall continue in full force and effect until October 31, 2020. Shipper and Transporter agree to avail themselves of the Commission's pre-granted abandonment authority upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's Regulations and Transporter's Tariff.

Section 3. Rates. Shipper shall pay the charges and furnish the Retainage as described in the above-referenced Rate Schedule, unless otherwise agreed to by the parties in writing and specified as an amendment to this Service Agreement. Transporter may agree to discount its rate to Shipper below Transporter's maximum rate, but not less than Transporter's minimum rate. Such discounted rate may apply to: (a) specified quantities (contract demand or commodity quantities); (b) specified quantities above or below a certain level or all quantities if quantities exceed a certain level; (c) quantities during specified time periods; (d) quantities at specified points, locations, or other defined geographical areas; (e) that a specified discounted rate will apply in a specified relationship to the quantities actually transported (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually transported); and (f) production and/or reserves committed by the Shipper.

Section 4. Notices. Notices to Transporter under this Agreement shall be addressed to it at 5151 San Felipe, Suite 2500, Houston, Texas 77056, Attention: Customer Services and notices to Shipper shall be addressed to it at Delta Natural Gas Company, Inc., Stanton Division, 3617 Lexington Road, Winchester, KY 40391, Attention: Brian Ramsey, until changed by either party by written notice.

Section 5. Superseded Agreements. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreement(s): FTS-1 No. 43827, Revision No. 2.

DELTA NATURAL GAS COMPANY, INC., STANTON DIVISION		COLUMBIA GULF TRANSMISSION, LLC	
By	Brian Ramsey	By	Edgar Trillo
Title	Vice President-Trans&Gas Supply	Title	Director
Date	October 29, 2015	Date	October 19, 2015

Revision No. 3

Appendix A to Service Agreement No. 43827
Under Rate Schedule FTS-1
between Columbia Gulf Transmission, LLC ("Transporter")
and Delta Natural Gas Company, Inc., Stanton Division ("Shipper")

Transportation Demand

Begin Date	End Date	Transportation Demand Dth/day	Recurrence Interval
November 1, 2015	October 31, 2020	860	1/1 - 12/31

Primary Receipt Points

Begin Date	End Date	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Recurrence Interval
November 1, 2015	October 31, 2020	2700010	CGT-RAYNE	860	1/1 - 12/31

Primary Delivery Points

Begin Date	End Date	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Recurrence Interval
November 1, 2015	October 31, 2020	801	GULF-LEACH	860	1/1 - 12/31

The Master List of Interconnects ("MLI") as defined in Section 1 of the General Terms and Conditions of Transporter's Tariff is incorporated herein by reference for purposes of listing valid secondary interruptible receipt points and delivery points.

Transporter and Shipper have mutually agreed to the following maximum or minimum pressure commitments:

____

____

_____ Yes __X__ No (Check applicable blank) Transporter and Shipper have mutually agreed to a Regulatory Restructuring Reduction Option pursuant to Section 33 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) Shipper has a contractual right of first refusal equivalent to the right of first refusal set forth from time to time in Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to the provisions of General Terms and Conditions Section 4. Right of first refusal rights, if any, applicable to this interim capacity are limited as provided for in General Terms and Conditions Section 4.

DELTA NATURAL GAS COMPANY, INC., STANTON DIVISION

By	Brian Ramsey
Title	Vice President-Trans&Gas Supply
Date	October 29, 2015

COLUMBIA GULF TRANSMISSION, LLC

By	Edgar Trillo
Title	Director
Date	October 19, 2015

Service Agreement No. 43829
Revision No. 3

FTS-1 SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 29 day of October, 2015, by and between COLUMBIA GULF TRANSMISSION, LLC ("Transporter") and DELTA NATURAL GAS COMPANY, INC. ("Shipper").

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. Transporter shall perform and Shipper shall receive the service in accordance with the provisions of the effective FTS-1 Rate Schedule and applicable General Terms and Conditions of Transporter's FERC Gas Tariff, Third Revised Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission herein contained. The maximum obligations of Transporter to deliver gas hereunder to or for Shipper, the designation of the points of delivery at which Transporter shall deliver or cause gas to be delivered to or for Shipper, and the points of receipt at which the Shipper shall deliver or cause gas to be delivered, are specified in Appendix A, as the same may be amended from time to time by agreement between Shipper and Transporter, or in accordance with the rules and regulations of the Commission.

Section 2. Term. Service under this Agreement shall commence as of November 1, 2015, and shall continue in full force and effect until October 31, 2020. Shipper and Transporter agree to avail themselves of the Commission's pre-granted abandonment authority upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's Regulations and Transporter's Tariff.

Section 3. Rates. Shipper shall pay the charges and furnish the Retainage as described in the above-referenced Rate Schedule, unless otherwise agreed to by the parties in writing and specified as an amendment to this Service Agreement. Transporter may agree to discount its rate to Shipper below Transporter's maximum rate, but not less than Transporter's minimum rate. Such discounted rate may apply to: (a) specified quantities (contract demand or commodity quantities); (b) specified quantities above or below a certain level or all quantities if quantities exceed a certain level; (c) quantities during specified time periods; (d) quantities at specified points, locations, or other defined geographical areas; (e) that a specified discounted rate will apply in a specified relationship to the quantities actually transported (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually transported); and (f) production and/or reserves committed by the Shipper.

Section 4. Notices. Notices to Transporter under this Agreement shall be addressed to it at 5151 San Felipe, Suite 2500, Houston, Texas 77056, Attention: Customer Services and notices to Shipper shall be addressed to it at Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, KY 40391, Attention: Brian Ramsey, until changed by either party by written notice.

Section 5. Superseded Agreements. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreement(s): FTS-1 No. 43829, Revision No. 2.

DELTA NATURAL GAS COMPANY, INC.		COLUMBIA GULF TRANSMISSION, LLC	
By	Brian Ramsey	By	Edgar Trillo
Title	Vice President-Trans&Gas Supply	Title	Director
Date	October 29, 2015	Date	October 19, 2015

Revision No. 3

Appendix A to Service Agreement No. 43829
Under Rate Schedule FTS-1
between Columbia Gulf Transmission, LLC ("Transporter")
and Delta Natural Gas Company, Inc. ("Shipper")

Transportation Demand

Begin Date	End Date	Transportation Demand Dth/day	Recurrence Interval
November 1, 2015	October 31, 2020	1,682	1/1 - 12/31

Primary Receipt Points

Begin Date	End Date	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Recurrence Interval
November 1, 2015	October 31, 2020	2700010	CGT-RAYNE	1,682	1/1 - 12/31

Primary Delivery Points

Begin Date	End Date	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Recurrence Interval
November 1, 2015	October 31, 2020	801	GULF-LEACH	1,682	1/1 - 12/31

The Master List of Interconnects ("MLI") as defined in Section 1 of the General Terms and Conditions of Transporter's Tariff is incorporated herein by reference for purposes of listing valid secondary interruptible receipt points and delivery points.

Transporter and Shipper have mutually agreed to the following maximum or minimum pressure commitments:

_____ Yes __X__ No (Check applicable blank) Transporter and Shipper have mutually agreed to a Regulatory Restructuring Reduction Option pursuant to Section 33 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) Shipper has a contractual right of first refusal equivalent to the right of first refusal set forth from time to time in Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to the provisions of General Terms and Conditions Section 4. Right of first refusal rights, if any, applicable to this interim capacity are limited as provided for in General Terms and Conditions Section 4.

DELTA NATURAL GAS COMPANY, INC.		COLUMBIA GULF TRANSMISSION, LLC	
By	Brian Ramsey	By	Edgar Trillo
Title	Vice President-Trans&Gas Supply	Title	Director
Date	October 29, 2015	Date	October 19, 2015

OPERATIONAL BALANCING AGREEMENT 60242 – Revision No. 3

This Operational Balancing Agreement ("Agreement") is made and entered into to be effective as of the 1st day of November, 2017, by and between Columbia Gulf Transmission, LLC ("Columbia") and Delta Natural Gas Company, Inc., Winchester Division, ("Customer"), collectively referred to herein as the "Parties," or individually as a "Party."

WITNESSETH:

WHEREAS, the parties operate certain pipeline facilities which interconnect at the point(s) (the "Interconnection Point(s)") identified in Exhibit A attached hereto;

WHEREAS, one or both Parties have entered into one or more transportation agreements with various shippers (the "Shippers") whereby the Parties either receive gas which the Shippers cause to be delivered at the Interconnection Point(s) or deliver gas which the Shippers cause to be received at the Interconnection Point(s);

WHEREAS, from time to time the aggregate quantity of gas delivered to or by the Parties at the Interconnection Point(s) is greater or less than the aggregate quantity of gas nominated by the Shippers and confirmed by the Parties at the Interconnection Points, resulting in the inadvertent over-delivery or under-delivery of gas by one Party to the other Party relative to the Shippers' nominated quantities (the "Operational Imbalance");

WHEREAS, the Parties desire to provide for a means whereby certain actions will be taken by them in order to prevent the occurrence of an Operational Imbalance at the Interconnection Point(s) and to reduce or eliminate any Operational Imbalance which may occur at the Interconnection Point(s);

NOW THEREFORE, in consideration of the mutual covenants and provisions herein contained and subject to all of the terms, provisions and conditions herein set forth, the Parties do hereby agree as follows:

ARTICLE I
RECONCILIATION OF OPERATIONAL IMBALANCES

1.1 Nominations at the Interconnection Points will be confirmed in accordance with Section 6 (Nominating, Scheduling and Monitoring) of Columbia's FERC Gas Tariff. The Parties intend that the quantities of gas actually delivered and received each day at the Interconnection Point(s) will equal the confirmed nominations, and the party controlling the flow at the Interconnection Point(s), as set forth on Exhibit A, shall control such flow accordingly. Each Party shall allocate the volumes to be delivered and received at the Interconnection Point(s) among the Shippers in accordance with the confirmed nominations. Any difference between the aggregate quantity of gas nominated and the aggregate quantity of gas actually delivered at the Interconnection Point(s) on any given day by each Party shall constitute the Operational Imbalance for each Party for that day (the "Daily Operational Imbalance").

1.2 During any given month, estimated meter quantities (Dth) shall be used by each Party on a daily basis to determine the estimated Daily Operational Imbalance, if any, at the Interconnection Point(s) for any given day. The Parties shall promptly make such physical flow adjustments as may be necessary in order to prevent, reduce or eliminate any Daily Operational

Imbalance. The daily variance in the estimated Daily Operational Imbalance should not exceed five percent (5%) of the aggregate quantities nominated for the day, nor two percent (2%) of the aggregate monthly quantities.

1.3 The sum of estimated Daily Operational Imbalances for each day in a given month shall constitute the estimated Monthly Operational Imbalance for such month. By the fifth day of the month following any given month in which an estimated Monthly Operational Imbalance arises, the measuring Party, as identified on Exhibit A, will notify the other Party as to the estimated Monthly Operational Imbalance for the prior month, and the Parties shall promptly make such physical flow modifications as may be necessary to reduce or eliminate any such Monthly Operational Imbalance. Should an imbalance occur, Columbia reserves the right to require a resolution of this imbalance within forty-eight (48) hours.

1.4 The actual MMBtu at the Interconnection Point(s) each month will be determined and the actual Monthly Operational Imbalance communicated by the allocating Party to the other Party in writing as soon as possible, but in no case later than the fifteenth day of the month following the month in which the actual Monthly Operational Imbalances arises. The Parties shall correct any actual Monthly Operational Imbalance by the end of the month within which the actual Monthly Operational Imbalance is determined, or within such longer period of time as may be agreed to by the Parties. Deliveries of gas to correct actual Monthly Operational Imbalances may be made between the parties at the Interconnection Point(s) set forth on Exhibit "A", or at any other point of interconnection between the respective facilities of the Parties as may be mutually agreed to by the Parties.

1.5 Any gas volumes received and delivered to correct an Operational Imbalance shall be adjusted for variations in Btu content in accordance with the applicable provisions of the FERC Gas Tariff of the Party which received the gas. Measurement of gas for all purposes hereunder shall be in accordance with the provisions set forth in the measuring Party's then effective FERC Gas Tariff.

1.6 In the event that a capacity constraint occurs on Columbia Gulf's pipeline system or at the Interconnection Point which results in reduction of nominations through an Interconnection Point, Columbia Gulf shall determine the appropriate capacity allocation of quantities pursuant to Columbia Gulf's FERC Gas Tariff Section 7.

ARTICLE II
TERM

This Agreement shall be effective and the procedures set forth in this Agreement shall be implemented as of the day and year first above written, and shall continue in effect month-to-month thereafter; provided, however that either Party may terminate this Agreement at any time by giving forty-eight (48) hours prior written notice of termination to the other Party, to be effective at the end of the month of such notification.

ARTICLE III
COMPLIANCE WITH TARIFF

In the event that any provision of this Agreement conflicts with any provision of Columbia's FERC Gas Tariff or transportation agreements, the applicable provision of the FERC Gas Tariff or transportation agreements shall take precedence over the conflicting provisions of this Agreement. Customer agrees that it will comply with all provisions of Columbia's FERC Gas Tariff including but not limited to Section 9 (Operating Conditions) and Section 17 (Operational Flow Orders). Columbia reserves the right to apply Section 9.6 (Creditworthiness of Shipper) of its Tariff to any imbalance which may occur under this Agreement.

ARTICLE IV
NOTICES

Any written notice shall be deemed delivered when transmitted by facsimile, or when mailed, by either certified or ordinary mail, postage prepaid, to the post office address of either of the Parties hereto, as the case may be, as follows:

Delta Natural Gas Company, Inc., Winchester Division
3617 Lexington Road
Winchester, KY 40391

Attention: Brian Ramsey, Vice President
Phone: (859) 744-6171
Fax: (866) 895-6155

Columbia Gulf Transmission, LLC
5151 San Felipe, Suite 2500
Houston, Texas 77056

Attention: Cynthia Burnette, Manager
Phone: (304) 357-3059
Fax: (304) 357-2654

A Party's phone or fax numbers or address set forth herein may be changed from time to time by giving written notice of such change to the other Party. Such changes shall be effective upon actual receipt of such notice by the other Party.

ARTICLE V
NO THIRD PARTY BENEFICIARIES

This Agreement shall not create any rights in third parties, and no provision of this Agreement shall be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than the Parties.

ARTICLE VI
STANDARD OF PERFORMANCE

The Parties understand and agree that performance under this Agreement shall occur only on a good faith basis. In the event of nonperformance or noncompliance by either Party with respect to one or more of the conditions set forth herein, such Party shall not be liable in any manner to the other Party or to any third parties for such nonperformance or noncompliance; except that, the Parties shall be legally obligated to reconcile any outstanding actual Operational Imbalance under this Agreement and which may exist upon termination of this Agreement consistent with the relevant terms and conditions set forth in this Agreement.

ARTICLE VII
GOVERNING LAW

The construction and interpretation of this Agreement shall be governed by the laws of the State of Texas, excluding any conflict of law rule which would refer any matter to the laws of a jurisdiction other than the State of Texas.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by its duly authorized officers to be effective as of the day and year first above written.

COLUMBIA GULF TRANSMISSION, LLC

By: Cynthia Burnette

Name: Cynthia Burnette

Title: Manager

Date: 10/30/17

DELTA NATURAL GAS COMPANY, INC., WINCHESTER DIVISION

By: Brian Ramsey

Name: Brian Ramsey

Title: Vice President

Date: 11/14/17

OPERATIONAL BALANCING AGREEMENT 60242 – Revision No. 3

EXHIBIT A
Interconnection Point(s)

Scheduling Point Name	Location County, State
DELTA	Madison, KY

GTS RATE SCHEDULE
GENERAL TRANSPORTATION SERVICE

1. AVAILABILITY

(a) Service under this Rate Schedule is available from Columbia Gas Transmission, LLC (Transporter) to any Shipper that as of May 18, 1992, either was a Shipper under Transporter's SGS Rate Schedule or had an executed Precedent Agreement with Transporter for service under the SGS Rate Schedule, provided that (i) Transporter has sufficient facilities and transportation capacity available to receive from or on behalf of Shipper and deliver gas to or for Shipper, (ii) Transporter has awarded capacity to Shipper pursuant to Transporter's Order No. 636 restructuring proceeding in FERC Docket No. RS92-5-000, (iii) Shipper has executed a GTS Service Agreement with Transporter for a Transportation Demand not exceeding 10,000 Dth per Day, and (iv) Shipper complies with all applicable provisions of this Rate Schedule and with all other applicable provisions of this Tariff.

2. APPLICABILITY AND CHARACTER OF SERVICE

(a) Service provided under this Rate Schedule shall be performed under Subpart B or G of Part 284 of the Commission's Regulations. Subject to the limitations set forth below, Transporter under this Rate Schedule (i) shall receive scheduled quantities from or on behalf of Shipper and shall deliver thermally equivalent quantities, less Retainage, to or for Shipper, and (ii) shall inject and store quantities and withdraw thermally equivalent quantities, less storage gas loss, for Shipper. Such service shall be provided on a firm basis and shall apply to all gas (i) received for Shipper under this Rate Schedule up to the Maximum Daily Quantity (MDQ) set forth in Shipper's GTS Service Agreement, (ii) stored by Transporter for Shipper under this Rate Schedule up to the Storage Contract Quantity (SCQ) set forth in Shipper's GTS Service Agreement, and (iii) delivered by Transporter to or for Shipper under this Rate Schedule up to the Transportation Demand set forth in Shipper's GTS Service Agreement.

(b) Shipper shall schedule its Scheduled Daily Receipt Quantity in accordance with the provisions of Section 6 (Nominating, Scheduling, and Monitoring) of the General Terms and Conditions. The sum of the receipt quantities at all of Shipper's primary receipt points may not exceed the Maximum Daily Quantity specified in Shipper's GTS Service Agreement.

(c) Shipper may schedule deliveries under this Rate Schedule on a no-notice basis, provided, however, that Transporter may require advance communication of changes in deliveries if it determines such communications necessary. Shipper may overrun its Transportation Demand on a given day to serve its historic service area if such overrun is made necessary by weather or other conditions beyond Shipper's control. To the extent that service is provided for deliveries to Shipper's historic service area, the Maximum Hourly Delivery Obligation limitations set forth in Section 9 (Operating Conditions) of the General Terms and Conditions shall not apply.

If Shipper's Transportation Demand is less than 10,000 Dth per day, Shipper may request from Transporter an increase up to a Transportation Demand of 10,000 Dth per day, provided that (i) Shipper's request complies with the provisions of Section 3 (Requests for Service) of the General Terms and Conditions, (ii) such requested increase is to provide service to Shipper's historic service area, and (iii) such requested increase would not result in Shipper's total Transportation Demand under its GTS Service Agreement with Transporter exceeding 10,000 Dth per day. Transporter may approve such a request if the capacity necessary to satisfy the request is available on its system or Transporter agrees to construct facilities to provide such capacity.

(d) Transporter shall store gas for Shipper in order to provide such gas to Shipper on the "no-notice" basis set forth herein up to the SCQ set forth in Shipper's GTS Service Agreement. Variances between actual deliveries of gas to or for Shipper and actual receipts of gas to or for Shipper on the same Day, less Retainage, shall be debited or credited to Shipper's storage account under this Rate Schedule, up to its SCQ. Shipper may in this manner withdraw from quantities actually in storage a cumulative quantity up to its SCQ, and a quantity in excess of its SCQ, up to twice its Transportation Demand; provided that, no later than 30 days after Transporter gives notice to Shipper, Shipper shall tender to Transporter quantities of gas in excess of its current deliveries sufficient to replenish all such quantities delivered from storage in excess of SCQ. If Shipper fails to replenish any such amounts in excess of SCQ withdrawn from storage, Shipper shall be subject to operational flow orders or interruption orders, and associated penalties, as set forth in Sections 2 and 6 of this Rate Schedule.

(e) Service provided under this Rate Schedule, including all injections and withdrawals from storage under this Rate Schedule, (i) shall have the priority specified in Section 7 (Capacity Allocation) of the General Terms and Conditions, (ii) shall be subject to interruption to the extent provided in this Rate Schedule or in Section 16 (Interruptions of Service) of the General Terms and Conditions, and (iii) shall be subject to operational flow orders to the extent provided in this Rate Schedule and in Section 17 (Operational Flow Orders) of the General Terms and Conditions.

(f) Shipper shall remain responsible for all property or other taxes associated with the quantities held for Shipper in storage under this Rate Schedule. Transporter periodically shall report to Shipper the quantities in storage, allocated by State, to enable Shipper to calculate and pay all taxes associated with its storage quantities. Storage gas inventory owned by GTS shippers (a) in West Virginia shall be deemed to be in West Virginia storage fields, (b) in Ohio shall be deemed to be in Ohio storage fields, and (c) in Pennsylvania and Kentucky shall be deemed to be in Pennsylvania storage fields. With regard to Shippers under this Rate Schedule, all of Transporter's storage fields shall be treated conjunctively within each such State. Each Shipper's storage gas shall be deemed to be proportionally allocated to all of Transporter's storage fields in the applicable States based on total working gas in storage in those States.

(g) A GTS Service Agreement may be released and assigned in accordance with Section 14 (Release and Assignment of Service Rights) of the General Terms and Conditions, and subject to the provisions set forth in this Rate Schedule. Any such assignments shall not relieve a releasing Shipper from its obligation to replenish any deficiency in its SCQ on a timely basis, as required by Section 2(d) of this Rate Schedule.

3. MINIMUM FIXED COST CONTRIBUTION (MFCC)

(a) Each Shipper under this Rate Schedule shall have an Annual GTS Quantity set forth in its Service Agreement representing the quantities to be utilized to determine whether Shipper is subject to an MFCC under this Rate Schedule during the Contract Year (November 1 through October 31). Such Annual GTS Quantity shall not serve as a limitation on Shipper's throughput. For a Contract Year commencing on or after November 1, 1993, if a Shipper and its replacement shippers transport less than 65% of that Shipper's Annual GTS Quantity (the Threshold GTS Quantity), that Shipper shall be assessed an MFCC charge; provided that the aggregate quantities transported by all Shippers and their replacement shippers under this Rate Schedule during that Contract Year total less than the aggregate Threshold GTS Quantities of all Shippers.

(b) If, after the end of any Contract Year, Transporter determines that aggregate quantities transported by all Shippers and their replacement shippers under this Rate Schedule during that Contract Year totaled less than the aggregate Threshold GTS Quantities of all Shippers, Transporter shall assess an MFCC charge to each Shipper that failed to satisfy its Threshold GTS Quantity. That MFCC charge shall be calculated by multiplying (i) the fixed costs per Dth imbedded in the currently maximum effective one-part rate for service under this Rate Schedule first by (ii) the net Deficiency Quantity of all Shippers under this Rate Schedule, then by (iii) the ratio of Shipper's GTS Transportation Deficiency Quantity (Shipper's Threshold GTS Quantity minus the actual quantities it and its replacement shippers transported) to the gross Transportation Deficiency Quantity incurred by deficient Shippers under this Rate Schedule. The MFCC charge shall be billed to Shipper in 5 equal installments during the next succeeding January - May Billing Months, with carrying charges at the Commission-approved rate accruing from the close of the preceding Contract Year.

4. RECEIPT AND DELIVERY

Shippers under this Rate Schedule shall have flexible primary and secondary receipt point authority in accordance with the provisions of Section 11 (Flexible Primary and Secondary Receipt and Delivery Points) of the General Terms and Conditions. Flexible primary and secondary delivery point authority under this Rate Schedule shall only be available, in Transporter's reasonable discretion, to enable Shipper to provide increased service, up to the maximum quantities available under this Rate Schedule, within Shipper's historic service area.

5. RATE

(a) The charges to be paid by Shipper, as set forth in paragraph (b) below, shall be no higher than the applicable total effective maximum charges and no lower than the applicable total effective minimum charges set forth in the currently effective Part V.5 of this Tariff, unless otherwise mutually agreed to by Transporter and Shipper with respect to the charges identified in Section 5(b) below.

(b) For all service rendered under this Rate Schedule, Shipper each month shall pay Transporter the charges set forth below, unless otherwise mutually agreed to by Transporter and Shipper with respect to the charges identified in Sections 5(b) below and specified in Shipper's GTS Service Agreement.

(1) Minimum Fixed Cost Contribution. The demand surcharge, if any, calculated in accordance with Section 3 of this Rate Schedule.

(2) Commodity Charge. The maximum Commodity Charge per Dth of gas actually delivered each Day during the Month to or for the account of Shipper.

(3) Surcharges. The surcharges applicable to this Rate Schedule.

(4) Processing Charge. If applicable under Section 25.3 of the General Terms and Conditions, the Processing Charge per Dth of gas processed by Transporter in its gas processing facilities.

(5) Gathering Charge. In the event that Transporter transports Shipper's gas through any pipeline, classified as gathering, the Shipper shall pay the maximum Gathering Charges specified according to the currently effective Part V.14 (Currently Effective Rates, Gathering Rates) of this Tariff or the appropriate gathering service agreement for all gas transported through such pipeline during the billing month. Gas transported through the gathering meters shown in the list updated from time to time on Transporter's Electronic Bulletin Board, shall be subject to the applicable aforementioned gathering charge, provided that any such meter is located on or immediately upstream of pipelines classified as gathering plant on Transporter's books.

(c) The charges described above are subject to the adjustment in accordance with the procedures set forth in the General Terms and Conditions.

(d) From the quantities delivered into storage for Shipper, Transporter shall retain the Storage Gas Loss Retainage Percentage specified in the currently effective Part V.17. That percentage shall be subject to adjustment in accordance with Section 35 (Retainage Adjustment Mechanism) of the General Terms and Conditions.

(e) In addition to collecting the applicable charges and surcharges, Transporter shall retain from the gas tendered for transportation the effective Transportation Retainage Percentage set forth in the currently effective Part V.17 of this Tariff, unless otherwise negotiated by Transporter and Shipper, and specified in Shipper's GTS Service Agreement. That

Transportation Retainage Percentage shall be subject to the adjustment in accordance with Section 35 (Retainage Adjustment Mechanism) of the General Terms and Conditions.

(f) Notwithstanding the provisions in Section 22 (Possession of Gas) of the General Terms and Conditions, Shipper shall be responsible for obtaining its own insurance or self-insuring for any gas in storage, and shall hold Transporter harmless from any loss, cost, or expense arising from any loss of storage gas that results from a force majeure event.

6. PENALTIES

(a) If Shipper fails to interrupt service as directed by Transporter pursuant to this Rate Schedule or Section 16 (Interruptions of Service) of the General Terms and Conditions and thereby takes gas from or tenders gas to Transporter in excess of 103 percent of the lowered Scheduled Daily Receipt or Delivery Quantity (Lowered Quantity) set by Transporter's interruption order, Shipper shall be assessed and pay penalties based on a price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia" as published in Platts Gas Daily price survey.

(b) If Shipper fails to comply with an operational flow order issued by Transporter pursuant to Section 17 (Operational Flow Orders) of the General Terms and Conditions, a penalty based on a price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia" as published in Platts Gas Daily price survey shall be assessed to Shipper for all quantities in violation of that operational flow order.

7. CONVERSION RIGHT

(a) A Shipper under this Rate Schedule shall have a one-time, irrevocable right to convert all of its service entitlements under this Rate Schedule to an equivalent level of service entitlements under Transporter's FTS, NTS, SST, and FSS Rate Schedules, provided that Shipper gives written notice of its intent to convert at least one year in advance of exercise of such conversion right, or within such lesser time period agreed to by Transporter. After exercising such conversion right, a Shipper may not later return any of the converted service rights to service under the GTS Rate Schedule.

(b) A Shipper's level of service entitlements under Transporter's FTS, NTS, SST, and FSS Rate Schedules upon conversion of its service entitlements under this Rate Schedule shall be determined as follows: (i) Shipper's Storage Contract Quantity under Transporter's FSS Rate Schedule shall equal Shipper's Storage Contract Quantity set forth in its GTS Service Agreement; (ii) Shipper's Maximum Daily Storage Quantity under Transporter's FSS Rate Schedule shall equal Shipper's Transportation Demand set forth in its GTS Service Agreement less Shipper's Maximum Daily Quantity set forth in its GTS Service Agreement; (iii) Shipper's Transportation Demand under Transporter's SST Rate Schedule shall be determined in accordance with Section 2(a) of Transporter's SST Rate Schedule and using the Maximum Daily Storage Quantity determined in item (ii) above; and (iv) Shipper's Transportation Demand under Transporter's FTS Rate Schedule shall equal the Maximum Daily Quantity set forth in its GTS Service Agreement. Shipper may elect to take any portion of its FTS Transportation Demand as calculated in item (iv) immediately above under Transporter's NTS Rate Schedule.

8. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions are applicable to this Rate Schedule and are hereby made a part hereof, with the exception of Sections 19.1, 19.2, 19.4, 40, and 42.

Service Agreement No. 37813

Revision No. 6

GTS SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 29 day of October, 2015, by and between COLUMBIA GAS TRANSMISSION, LLC ("Transporter") and DELTA NATURAL GAS COMPANY, INC., CUMBERLAND DIVISION ("Shipper").

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. Transporter shall perform and Shipper shall receive service in accordance with the provisions of the effective GTS Rate Schedule and applicable General Terms and Conditions of Transporter's FERC Gas Tariff, Fourth Revised Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission. The maximum obligation of Transporter to deliver gas hereunder to or for Shipper, the designation of the points of delivery at which Transporter shall deliver or cause gas to be delivered to or for Shipper, and the points of receipt at which Shipper shall deliver or cause gas to be delivered, are specified in Appendix A, as the same may be amended from time to time by agreement between Shipper and Transporter, or in accordance with the rules and regulations of the Commission.

Section 2. Term. Service under this Agreement shall commence as of November 1, 2015, and shall continue from year to year thereafter until terminated by either Transporter or Shipper upon six months' prior notice. Pre-granted abandonment shall apply upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's regulations and Transporter's Tariff.

Section 3. Rates. Shipper shall pay Transporter the charges and furnish Retainage as described in the above-referenced Rate Schedule, unless otherwise agreed to by the parties in writing and specified as an amendment to this Service Agreement. Transporter may agree to discount its rate to Shipper below Transporter's maximum rate, but not less than Transporter's minimum rate. Such discounted rate may apply to: (a) specified quantities (contract demand or commodity quantities); (b) specified quantities above or below a certain level or all quantities if quantities exceed a certain level; (c) quantities during specified time periods; (d) quantities at specified points, locations, or other defined geographical areas; (e) that a specified discounted rate will apply in a specified relationship to the quantities actually transported (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually transported); (f) production and/or reserves committed by the Shipper; and (g) based on a formula including, but not limited to, published index prices for specific receipt and/or delivery points or other agreed-upon pricing points, provided that the resulting rate shall be no lower than the minimum nor higher than the maximum applicable rate set forth in the Tariff. In addition, the discount agreement may include a provision that if one rate component which was at or below the applicable maximum rate at the time the discount agreement was executed subsequently exceeds the applicable maximum rate due to a change in Transporter's maximum rate so that such rate component must be adjusted downward to equal the new applicable maximum rate, then other rate components may be adjusted upward to achieve the agreed overall rate, so long as none of the resulting rate components exceed the maximum rate applicable to that rate component. Such changes to rate components shall be applied prospectively, commencing with the date a Commission order accepts revised tariff sections. However, nothing contained herein shall be construed to alter a refund obligation under applicable law for any period during which rates, which had been charged under a discount agreement, exceeded rates which ultimately are found to be just and reasonable.

Section 4. Notices. Notices to Transporter under this Agreement shall be addressed to it at 5151 San Felipe, Suite 2500, Houston, Texas 77056, Attention: Customer Services and notices to Shipper shall be addressed to it at Delta Natural Gas Company, Inc., Cumberland Division, 3617 Lexington Road, Winchester, KY 40391, Attention: Brian Ramsey, until changed by either party by written notice.

Section 5. Superseded Agreements. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreement(s): GTS No. 37813, Revision No. 5.

DELTA NATURAL GAS COMPANY, INC., CUMBERLAND DIVISION

By	Brian Ramsey
Title	Vice President-Trans&Gas Supply
Date	October 29, 2015

COLUMBIA GAS TRANSMISSION, LLC

By	Cindy Burnette
Title	Manager-Customer Services
Date	October 28, 2015

Revision No. 6

Appendix A to Service Agreement No. 37813
Under Rate Schedule GTS
between Columbia Gas Transmission, LLC ("Transporter")
and Delta Natural Gas Company, Inc., Cumberland Division ("Shipper")

Storage Contract Quantity

Begin Date	End Date	Transportation Demand Dth/day	Storage Contract Quantity Dth	Annual GTS Quantity Dth/year	Recurrence Interval
November 1, 2015	N/A	5,400	177,662	98,200	1/1 - 12/31

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Minimum Receipt Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	1,800		1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Delivery Obligation (Dth/day) 1/	Minimum Delivery Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	34	DELTA NATRL CUMBRLND	805992	MANCHESTER	5,100	265	1/1 - 12/31
November 1, 2015	N/A	34	DELTA NATRL CUMBRLND	832867	BEATYVILLE	300	230	1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

1/ Application of MDDOs minimum pressure and/or hourly flowrate shall be as follows:

Unless Measuring Point specific Maximum Daily Delivery Obligations (MDDOs) are specified in a separate firm service agreement between Transporter and Shipper, Transporter's aggregate MDDO, under this and any other service agreement between Transporter and Shipper, at the Measuring Points listed above shall not exceed the MDDO quantities set forth above for each Measuring Point. Any Measuring Point specific MDDOs in a separate firm service agreement between Transporter and Shipper shall be additive to the individual Measuring Point MDDOs set forth above.

The Master List of Interconnects ("MLI") as defined in Section 1 of the General Terms and Conditions of Transporter's Tariff is incorporated herein by reference for purposes of listing valid secondary interruptible receipt points and delivery points.

_____ Yes __X__ No (Check applicable blank) Shipper has a contractual right of first refusal equivalent to the right of first refusal set forth in Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to the provisions of General Terms and Conditions Section 4. Right of first refusal rights, if any, applicable to this interim capacity are limited as provided for in General Terms and Conditions Section 4.

__X__ Yes _____ No (Check applicable blank) This Service Agreement covers offsystem capacity sold pursuant to section 47 of the General Terms and Conditions. Right of first refusal rights, if any, applicable to this offsystem capacity are limited as provided for in General Terms and Conditions Section 47.

DELTA NATURAL GAS COMPANY, INC., CUMBERLAND DIVISION		COLUMBIA GAS TRANSMISSION, LLC	
By	Brian Ramsey	By	Cindy Burnette
Title	Vice President-Trans&Gas Supply	Title	Manager-Customer Services
Date	October 29, 2015	Date	October 28, 2015

Service Agreement No. 37814

Revision No. 8

GTS SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 29 day of October, 2015, by and between COLUMBIA GAS TRANSMISSION, LLC ("Transporter") and DELTA NATURAL GAS COMPANY, INC., STANTON DIVISION ("Shipper").

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. Transporter shall perform and Shipper shall receive service in accordance with the provisions of the effective GTS Rate Schedule and applicable General Terms and Conditions of Transporter's FERC Gas Tariff, Fourth Revised Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission. The maximum obligation of Transporter to deliver gas hereunder to or for Shipper, the designation of the points of delivery at which Transporter shall deliver or cause gas to be delivered to or for Shipper, and the points of receipt at which Shipper shall deliver or cause gas to be delivered, are specified in Appendix A, as the same may be amended from time to time by agreement between Shipper and Transporter, or in accordance with the rules and regulations of the Commission.

Section 2. Term. Service under this Agreement shall commence as of November 1, 2015, and shall continue from year to year thereafter until terminated by either Transporter or Shipper upon six months' prior notice. Pre-granted abandonment shall apply upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's regulations and Transporter's Tariff.

Section 3. Rates. Shipper shall pay Transporter the charges and furnish Retainage as described in the above-referenced Rate Schedule, unless otherwise agreed to by the parties in writing and specified as an amendment to this Service Agreement. Transporter may agree to discount its rate to Shipper below Transporter's maximum rate, but not less than Transporter's minimum rate. Such discounted rate may apply to: (a) specified quantities (contract demand or commodity quantities); (b) specified quantities above or below a certain level or all quantities if quantities exceed a certain level; (c) quantities during specified time periods; (d) quantities at specified points, locations, or other defined geographical areas; (e) that a specified discounted rate will apply in a specified relationship to the quantities actually transported (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually transported); (f) production and/or reserves committed by the Shipper; and (g) based on a formula including, but not limited to, published index prices for specific receipt and/or delivery points or other agreed-upon pricing points, provided that the resulting rate shall be no lower than the minimum nor higher than the maximum applicable rate set forth in the Tariff. In addition, the discount agreement may include a provision that if one rate component which was at or below the applicable maximum rate at the time the discount agreement was executed subsequently exceeds the applicable maximum rate due to a change in Transporter's maximum rate so that such rate component must be adjusted downward to equal the new applicable maximum rate, then other rate components may be adjusted upward to achieve the agreed overall rate, so long as none of the resulting rate components exceed the maximum rate applicable to that rate component. Such changes to rate components shall be applied prospectively, commencing with the date a Commission order accepts revised tariff sections. However, nothing contained herein shall be construed to alter a refund obligation under applicable law for any period during which rates, which had been charged under a discount agreement, exceeded rates which ultimately are found to be just and reasonable.

Section 4. Notices. Notices to Transporter under this Agreement shall be addressed to it at 5151 San Felipe, Suite 2500, Houston, Texas 77056, Attention: Customer Services and notices to Shipper shall be addressed to it at Delta Natural Gas Company, Inc., Stanton Division, 3617 Lexington Road, Winchester, KY 40391, Attention: Brian Ramsey, until changed by either party by written notice.

Section 5. Superseded Agreements. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreement(s): GTS No. 37814, Revision No. 7.

DELTA NATURAL GAS COMPANY, INC.,
STANTON DIVISION

By	Brian Ramsey
Title	Vice President-Trans&Gas Supply
Date	October 29, 2015

COLUMBIA GAS TRANSMISSION, LLC

By	Cindy Burnette
Title	Manager-Customer Services
Date	October 28, 2015

Revision No. 8

Appendix A to Service Agreement No. 37814
Under Rate Schedule GTS
between Columbia Gas Transmission, LLC ("Transporter")
and Delta Natural Gas Company, Inc., Stanton Division ("Shipper")

Storage Contract Quantity

Begin Date	End Date	Transportation Demand Dth/day	Storage Contract Quantity Dth	Annual GTS Quantity Dth/year	Recurrence Interval
November 1, 2015	N/A	6,663	83,255	72,874	1/1 - 12/31

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Minimum Receipt Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	4,133		1/1 - 12/31
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	4,976		1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Delivery Obligation (Dth/day) 1/	Minimum Delivery Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	4,133		1/1 - 12/31
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	4,976		1/1 - 12/31
November 1, 2015	N/A	35	DELTA NATRL STANTON	800803	STANTON	2,530	200	1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

1/ Application of MDDOs minimum pressure and/or hourly flowrate shall be as follows:

Unless Measuring Point specific Maximum Daily Delivery Obligations (MDDOs) are specified in a separate firm service agreement between Transporter and Shipper, Transporter's aggregate MDDO, under this and any other service agreement between Transporter and Shipper, at the Measuring Points listed above shall not exceed the MDDO quantities set forth above for each Measuring Point. Any Measuring Point specific MDDOs in a separate firm service agreement between Transporter and Shipper shall be additive to the individual Measuring Point MDDOs set forth above.

The Master List of Interconnects ("MLI") as defined in Section 1 of the General Terms and Conditions of Transporter's Tariff is incorporated herein by reference for purposes of listing valid secondary interruptible receipt points and delivery points.

_____ Yes __X__ No (Check applicable blank) Shipper has a contractual right of first refusal equivalent to the right of first refusal set forth in Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to the provisions of General Terms and Conditions Section 4. Right of first refusal rights, if any, applicable to this interim capacity are limited as provided for in General Terms and Conditions Section 4.

__X__ Yes _____ No (Check applicable blank) This Service Agreement covers offsystem capacity sold pursuant to section 47 of the General Terms and Conditions. Right of first refusal rights, if any, applicable to this offsystem capacity are limited as provided for in General Terms and Conditions Section 47.

DELTA NATURAL GAS COMPANY, INC., STANTON DIVISION

By	Brian Ramsey
Title	Vice President-Trans&Gas Supply
Date	October 29, 2015

COLUMBIA GAS TRANSMISSION, LLC

By	Cindy Burnette
Title	Manager-Customer Services
Date	October 28, 2015

Exhibit 1-8

Service Agreement No. 37815

Revision No. 7

GTS SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 29 day of October, 2015, by and between COLUMBIA GAS TRANSMISSION, LLC ("Transporter") and DELTA NATURAL GAS COMPANY, INC. ("Shipper").

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. Transporter shall perform and Shipper shall receive service in accordance with the provisions of the effective GTS Rate Schedule and applicable General Terms and Conditions of Transporter's FERC Gas Tariff, Fourth Revised Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission. The maximum obligation of Transporter to deliver gas hereunder to or for Shipper, the designation of the points of delivery at which Transporter shall deliver or cause gas to be delivered to or for Shipper, and the points of receipt at which Shipper shall deliver or cause gas to be delivered, are specified in Appendix A, as the same may be amended from time to time by agreement between Shipper and Transporter, or in accordance with the rules and regulations of the Commission.

Section 2. Term. Service under this Agreement shall commence as of November 1, 2015, and shall continue from year to year thereafter until terminated by either Transporter or Shipper upon six months' prior notice. Pre-granted abandonment shall apply upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's regulations and Transporter's Tariff.

Section 3. Rates. Shipper shall pay Transporter the charges and furnish Retainage as described in the above-referenced Rate Schedule, unless otherwise agreed to by the parties in writing and specified as an amendment to this Service Agreement. Transporter may agree to discount its rate to Shipper below Transporter's maximum rate, but not less than Transporter's minimum rate. Such discounted rate may apply to: (a) specified quantities (contract demand or commodity quantities); (b) specified quantities above or below a certain level or all quantities if quantities exceed a certain level; (c) quantities during specified time periods; (d) quantities at specified points, locations, or other defined geographical areas; (e) that a specified discounted rate will apply in a specified relationship to the quantities actually transported (i.e., that the reservation charge will be adjusted in a specified relationship to quantities actually transported); (f) production and/or reserves committed by the Shipper; and (g) based on a formula including, but not limited to, published index prices for specific receipt and/or delivery points or other agreed-upon pricing points, provided that the resulting rate shall be no lower than the minimum nor higher than the maximum applicable rate set forth in the Tariff. In addition, the discount agreement may include a provision that if one rate component which was at or below the applicable maximum rate at the time the discount agreement was executed subsequently exceeds the applicable maximum rate due to a change in Transporter's maximum rate so that such rate component must be adjusted downward to equal the new applicable maximum rate, then other rate components may be adjusted upward to achieve the agreed overall rate, so long as none of the resulting rate components exceed the maximum rate applicable to that rate component. Such changes to rate components shall be applied prospectively, commencing with the date a Commission order accepts revised tariff sections. However, nothing contained herein shall be construed to alter a refund obligation under applicable law for any period during which rates, which had been charged under a discount agreement, exceeded rates which ultimately are found to be just and reasonable.

Section 4. Notices. Notices to Transporter under this Agreement shall be addressed to it at 5151 San Felipe, Suite 2500, Houston, Texas 77056, Attention: Customer Services and notices to Shipper shall be addressed to it at Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, KY 40391, Attention: Brian Ramsey, until changed by either party by written notice.

Section 5. Superseded Agreements. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreement(s): GTS No. 37815, Revision No. 6.

DELTA NATURAL GAS COMPANY, INC.		COLUMBIA GAS TRANSMISSION, LLC	
By	Brian Ramsey	By	Cindy Burnette
Title	Vice President-Trans&Gas Supply	Title	Manager-Customer Services
Date	October 29, 2015	Date	October 28, 2015

Revision No. 7

Appendix A to Service Agreement No. 37815
Under Rate Schedule GTS
between Columbia Gas Transmission, LLC ("Transporter")
and Delta Natural Gas Company, Inc. ("Shipper")

Storage Contract Quantity

Begin Date	End Date	Transportation Demand Dth/day	Storage Contract Quantity Dth	Annual GTS Quantity Dth/year	Recurrence Interval
November 1, 2015	N/A	4,950	162,857	117,101	1/1 - 12/31

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Quantity (Dth/day)	Minimum Receipt Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	801	TCO-LEACH	801	TCO-LEACH	1,650		1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Measuring Point No.	Measuring Point Name	Maximum Daily Delivery Obligation (Dth/day) 1/	Minimum Delivery Pressure Obligation (psig) 1/	Recurrence Interval
November 1, 2015	N/A	36-10	DNG-WIN	803545	DELTA-OWINGSVILLE	1,030		1/1 - 12/31
November 1, 2015	N/A	36-10	DNG-WIN	803564	SHARPSBURG DELTA GAS	220		1/1 - 12/31
November 1, 2015	N/A	36-12	DELTA NATRL WINCH-12	800809	KINGSTON TERRELL	2,270	200	1/1 - 12/31
November 1, 2015	N/A	36-12	DELTA NATRL WINCH-12	803512	DELTA-N. MIDDLETOWN	310	100	1/1 - 12/31
November 1, 2015	N/A	36-12	DELTA NATRL WINCH-12	803563	CARMARGO	340		1/1 - 12/31
November 1, 2015	N/A	36-14	DELTA NATRL WINCH-14	803544	FRENCHBURG	280	150	1/1 - 12/31
November 1, 2015	N/A	47	DELTA NATRL WINCH-10	804148	DELTA NATURAL GAS CO	500		1/1 - 12/31
November 1, 2015	N/A	STOR	RP Storage Point TCO			0		1/1 - 12/31

1/ Application of MDDOs minimum pressure and/or hourly flowrate shall be as follows:

Unless Measuring Point specific Maximum Daily Delivery Obligations (MDDOs) are specified in a separate firm service agreement between Transporter and Shipper, Transporter's aggregate MDDO, under this and any other service agreement between Transporter and Shipper, at the Measuring Points listed above shall not exceed the MDDO quantities set forth above for each Measuring Point. Any Measuring Point specific MDDOs in a separate firm service agreement between Transporter and Shipper shall be additive to the individual Measuring Point MDDOs set forth above.

The Master List of Interconnects ("MLI") as defined in Section 1 of the General Terms and Conditions of Transporter's Tariff is incorporated herein by reference for purposes of listing valid secondary interruptible receipt points and delivery points.

_____ Yes __X__ No (Check applicable blank) Shipper has a contractual right of first refusal equivalent to the right of first refusal set forth in Section 4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

_____ Yes __X__ No (Check applicable blank) This Service Agreement covers interim capacity sold pursuant to the provisions of General Terms and Conditions Section 4. Right of first refusal rights, if any, applicable to this interim capacity are limited as provided for in General Terms and Conditions Section 4.

__X__ Yes _____ No (Check applicable blank) This Service Agreement covers offsystem capacity sold pursuant to section 47 of the General Terms and Conditions. Right of first refusal rights, if any, applicable to this offsystem capacity are limited as provided for in General Terms and Conditions Section 47.

DELTA NATURAL GAS COMPANY, INC.

By	Brian Ramsey
Title	Vice President-Trans&Gas Supply
Date	October 29, 2015

COLUMBIA GAS TRANSMISSION, LLC

By	Cindy Burnette
Title	Manager-Customer Services
Date	October 28, 2015

OPERATIONAL BALANCING AGREEMENT ("AGREEMENT")
BETWEEN
TEXAS EASTERN TRANSMISSION, LP
AND
DELTA NATURAL GAS CO INC

This Agreement is made and effective as of the 15th day of September, 2016, by DELTA NATURAL GAS CO INC ("OBA Party") and by Texas Eastern Transmission, LP ("TETLP"), collectively referred to as "Parties" or individually referred to as a "Party".

WITNESSETH

WHEREAS, the pipeline facilities operated by the Parties interconnect at the interconnection point(s) specified on Exhibit 1 attached hereto and incorporated herein by this reference (hereinafter referred to as "Location", whether one or more); and

WHEREAS, Party or Parties have entered into one or more agreements with third party Service Requesters ("Service Requester(s)") for the transportation of natural gas to or from the Location on the Parties' respective systems (said agreements hereinafter referred to as "Service Requester Agreements"); and

WHEREAS, from time to time, dekatherms of natural gas confirmed and scheduled by the Parties to be delivered to or received from the Location (said quantities hereinafter referred to as "Scheduled Quantities") may be greater than or less than the dekatherms of natural gas which are actually delivered at the Location, resulting in inadvertent over- or under-deliveries of the Service Requesters' Scheduled Quantities; and

WHEREAS, the Parties desire to implement an operational balancing agreement in order to facilitate more efficient operations, accounting, and systems management at the Location and on the Parties' respective systems; and

NOW, THEREFORE, in consideration of the premises and mutual covenants contained herein, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Article 1: Operational Parameters

(1.1) Prior to the date and time of flow at each Location, the Parties shall confirm and schedule Service Requester(s) nominations which will be delivered or received at each Location. Such confirmation between the Parties shall be made electronically via electronic interface system (such as the Parties' Electronic Bulletin Boards or other successor systems), unless otherwise mutually agreed to by the Parties.

(1.2) The Parties intend that the total dekatherms of natural gas actually delivered and received each gas day at each Location will equal the Scheduled Quantities for said Location. Each Party will allocate the dekatherms that have been delivered and received at each Location among the Service Requester Agreements on its system pursuant to the Scheduled Quantities at each such Location. Any difference between the total actual physical flow of gas and the total of all Scheduled Quantities at each Location for such gas day is defined for the purposes of this Agreement as the "Daily Operational Imbalance". The sum of all unresolved Daily Operational Imbalances at any given time is defined for purposes of this Agreement as the "Cumulative Operational Imbalance". The Parties shall eliminate such Daily Operational Imbalance and Cumulative Operational Imbalance pursuant to this Agreement.

(1.3) Unless the Parties otherwise mutually agree, the best available operating data for gas flows at the Location shall be used on a daily basis during any current period to determine the estimated

Cumulative Operational Imbalance at the Location, with physical flow adjustments to be made during that current period as mutually agreed to by both Parties to attempt to maintain or achieve a Cumulative Operational Imbalance of zero at the Location. The Cumulative Operational Imbalance shall be calculated by Measuring Party no later than the tenth (10^{th}) day of the following month.

(1.4) Any Cumulative Operational Imbalance calculated pursuant to paragraph (1.3) above for said month shall be agreed to by electronic interface systems or in writing by the Parties prior to the tenth (10th) day of such month. Such Cumulative Operational Imbalance shall be resolved by the Parties pursuant to mutually agreed upon procedures, which shall be negotiated by the Parties on a not unduly discriminatory basis.

Article 2: Term and Effectiveness

(2.1) Upon the termination of this Agreement, the Parties agree to reconcile and eliminate any remaining Cumulative Operational Imbalance pursuant to the terms and conditions of this Agreement within thirty (30) days of termination of this Agreement or such other period of time which is mutually agreed upon by the Parties. Or, upon mutual agreement by the Parties, the Cumulative Operational Imbalance may be resolved by cash out according to the provisions of TETLP's FERC Gas Tariff.

(2.2) Subject to the provisions of this Article 2, this Agreement shall be effective as of the effective date and shall continue from month to month thereafter until terminated by either Party upon not less than thirty (30) days' prior written notice.

(2.3) Notwithstanding the provisions of Paragraph (2.2), this Agreement can be terminated by either Party under the following conditions:

(a) Failure by either Party to immediately adjust the operations of its system when informed in writing or by electronic interface system of a critical operating condition(s) by the other Party. A critical operating condition is determined in the sole reasonable judgment of the Party claiming a critical operating condition.

(b) Failure of the Parties to agree in writing on the final adjusted Cumulative Operational Imbalance prior to the fifteenth (15th) day of the month following the last month gas was delivered; provided, however, if the Parties disagree on the final adjusted Cumulative Operational Imbalance but are diligently working towards a resolution, then this Agreement will not terminate.

Article 3: Miscellaneous

(3.1) This Agreement and the terms and conditions herein are subject to all present and future valid laws, orders, rules and regulations established by a governmental body with jurisdiction that is applicable to the Parties and this Agreement.

(3.2) In the event a conflict exists or arises between this Agreement and the TETLP FERC Gas Tariff, as amended from time to time, it is agreed and understood that the latter shall control. This Agreement shall supersede any other agreements with respect to the handling of a Daily Operational Imbalance and the Cumulative Operational Imbalance at the Location.

(3.3) OBA Party hereby acknowledges and agrees that the provisions of TETLP's FERC Gas Tariff are incorporated herein by reference and made a part of this Agreement for all purposes, and that such FERC Gas Tariff provisions shall be applicable to operations on TETLP's pipeline system, including any and all rights and obligations of TETLP pursuant to this Agreement and any and all rights and obligations of OBA Party pursuant to this Agreement. OBA Party also agrees that it shall be required to comply with all of the creditworthiness requirements in TETLP's FERC Gas Tariff throughout the term of this Agreement.

(3.4) This Agreement is for accounting and system management purposes only, and is entered into by the Parties with the understanding that the balancing activities provided for hereunder will not subject any non-jurisdictional entity to regulation by the Federal Energy Regulatory Commission as a "natural gas company" under the provisions of the Natural Gas Act. If, at any time, it should be determined that such balancing activities do result in such regulation, then this Agreement shall immediately terminate, and any remaining Cumulative Operational Imbalance shall be resolved pursuant to Paragraph (2.1) of this Agreement.

(3.5) This Agreement is not assignable.

(3.6) This Agreement shall be construed in accordance with the laws of the State of Texas without regard to conflicts of law principles. EACH PARTY HEREBY IRREVOCABLY WAIVES ANY AND ALL RIGHTS TO TRIAL BY JURY IN ANY ACTION ARISING UNDER THIS AGREEMENT.

(3.7) No waiver by either Party of any one or more defaults by the other in the performance of any provision of this Agreement shall operate or be construed as a waiver of any continuing or future default or defaults, whether of a like or different character, or a waiver of each of the Parties' obligations to eliminate a Daily Operational Imbalance or the Cumulative Operational Imbalance by adjusting nominations and, or, deliveries and receipts of gas at the Location, as provided herein.

(3.8) The Parties intend that there shall be no third party beneficiary to this Agreement. Nothing in this Agreement shall entitle any persons other than OBA Party or TETLP, to any claim, cause of action, remedy or right of any kind relating to the transaction(s) contemplated by this Agreement.

(3.9) As provided in this Agreement, written notices shall be mailed to the post office address of the Party intended to receive the same, as follows:

(OBA Party):
Address:
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

Texas Eastern:
P. O. Box 1642
Houston, Texas 77251-1642
Attention: Operational Balancing

(3.10) This Agreement constitutes the entire agreement between the Parties concerning the subject matters of this Agreement, and there are no oral or other written agreements relating to such matters.

(3.11) This Agreement supercedes and cancels, as of the effective date of this Agreement, the contract(s) between the Parties hereto as described below:

None

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement by their duly authorized representatives effective on the date set forth hereinabove.

TEXAS EASTERN TRANSMISSION, LP
By its General Partner
Spectra Energy Transmission Services, LLC

By: Executed Online by SHAMUS P DONAHOE

Name: SHAMUS P DONAHOE

(OBA PARTY)

By: Executed Online by WAYNE T HUNTER II

Name: WAYNE T HUNTER II

EXHIBIT 1
To the Operational Balancing Agreement
Between
Texas Eastern Transmission, LP
DELTA NATURAL GAS CO INC ("OBA Party")

Date: 09/15/2016

Location

TETLP M&R	Description
73131	DELTA NAT GAS - MADISON CO, KY CO., KY
73196	DELTA NAT GAS -MADISON CO., KY CO., KY

TEXAS EASTERN TRANSMISSION, LP
By its General Partner
Spectra Energy Transmission Services, LLC

By: Executed Online by SHAMUS P DONAHOE

Name: SHAMUS P DONAHOE

(OBA PARTY)

By: Executed Online By WAYNE T HUNTER II

Name: WAYNE T HUNTER II

THIS IS A TRUE COPY OF A SIGNED CONTRACT EXECUTED ELECTRONICALLY ON LINK

 Contract No.: 630455-R1A1

RATE SCHEDULE FT-GS
SMALL CUSTOMER TRANSPORTATION SERVICE

1. AVAILABILITY

This Rate Schedule is available for the transportation of natural gas on a firm basis by Tennessee Gas Pipeline Company, L.L.C. (Transporter) for any Party (Shipper)

(a) which is a pipeline, a local distribution company, or a municipality with a pipeline or distribution system which connects with or which can be made to connect with, either directly or through third parties, Transporter's main trunk transmission line; and

(b) which (i) was served under Transporter's previously effective Rate Schedules G or GS, or (ii) received 10,000 dth or less on any day under all services on Transporter's system and was directly served as a sales customer by a customer of Transporter on July 1, 1993; and

(c) which has elected such service and has executed a service agreement for service under Rate Schedule FT-GS; and

(d) where the maximum daily quantity for firm service to Shipper cannot exceed 10,000 dth/d at a stated point of delivery, unless such larger quantity was effective under a Rate Schedule G or GS Sales Service Agreement with Transporter effective on the date prior to implementation of this Schedule. In such case, the maximum daily quantity shall be limited to the maximum daily quantity stated in the previously effective Rate Schedule G or GS.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Transportation service hereunder will be firm, except as provided herein and in the General Terms and Conditions.

2.2 A Customer executing a service agreement under this Rate Schedule (referred to as "Customer" or "Shipper") shall have a Transportation Quantity which is not more than 10,000 Dth/day or which is equal to the Maximum Daily Obligation contained in the Customer's former service agreement under Rate Schedule G or GS.

2.3 A Customer executing a service agreement under this Rate Schedule has the right to make an election to convert its service in its entirety to firm transportation service under Rate Schedule FT-A or FT-G by providing written notice of such election on or before June 1 of any year. Any such conversion shall be effective as of the following November 1.

2.4 Unless Shipper has elected the True-Up Payment Option as specified in Section 2.5 hereof, Transporter shall not schedule and Shipper shall not receive gas for ultimate use in a portion of Shipper's distribution system served by Shipper's FT-GS Delivery Point(s) utilizing any other Rate Schedule or any third party (except to effectuate deliveries hereunder), unless and until Transporter has scheduled (or allocated from Shipper's FS Service) the Transportation Quantity as set forth in Shipper's FT-GS Transportation Service Agreement(s) attributable to that portion of Shipper's distribution system. This restriction shall not apply to Shipper's receiving gas withdrawn from third party storage, provided that such gas was injected by Shipper in compliance with this Section 2.4; provided, further, this restriction shall not apply to service for ultimate use by designated end users in any portion of Shipper's distribution system served by Shipper's Delivery Point(s); provided that separate meters are in place downstream of Shipper's Delivery Point(s) verifying delivery of such quantities to such designated end users. Upon the request of Transporter, Shipper shall provide a statement verifying compliance with this Section 2.4 provision for the prior calendar year.

RATE SCHEDULE FT-GS
SMALL CUSTOMER TRANSPORTATION SERVICE (continued)

2. APPLICABILITY AND CHARACTER OF SERVICE (continued)

2.5 True-up Payment Option: Any Shipper desiring to receive IT service, released capacity or transportation from third party pipelines, may do so on an unrestricted basis if such Shipper:

(a) notifies Transporter of its election of this True-Up Payment Option no later than December 1 of any year to be effective on January 1 of the following year; and

(b) agrees to an annual FT-GS revenue responsibility based on the established FT-GS billing determinants. If payments for gas transported under this Rate Schedule fall short of Shipper's annual FT-GS revenue responsibility of any year in which Shipper has elected this True-Up Payment Option ("True-Up Payment Option Year"), Transporter shall bill Shipper for the shortfall, if any, between payments made during the year and Shipper's revenue responsibility.

On December 1 of the True-Up Payment Option Year, Transporter shall determine the shortfall between payments under Rate Schedule FT-GS and Shipper's FT-GS revenue responsibility by adding actual payments received and forecasted payments for the remainder of the True-Up Payment Option Year, then subtracting the total from Shipper's FT-GS revenue responsibility. On or before December 15 of the True-Up Payment Option Year, Transporter shall bill Shipper for any shortfall. Upon receipt of the actual payments for the remainder of the True-Up Payment Option Year, Transporter shall credit or bill Shipper for the difference, if appropriate.

2.6 Transporter shall not be required to install, operate or maintain any additional facilities in order to provide transportation service under this Rate Schedule.

3. QUALIFICATION FOR SERVICE

3.1 All Customers electing to convert existing service to transportation service under this Rate Schedule must satisfy the requirements specified in Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff.

3.2 Transporter shall evaluate any complete, valid request for service based upon the criteria set forth in Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff, and as provided for under this Rate Schedule.

4. DELIVERIES AND RECEIPTS

4.1 Receipt Points: Subject to the availability of capacity, any receipt point on Transporter's system, including Pooling Area Points, shall be eligible for designation as a Primary Receipt Point on Shipper's Transportation Service Agreement. Any receipt point in Shipper's Transportation Path may be used as a Secondary Receipt Point.

4.2 Delivery Points: Shipper's delivery points shall be the interconnection(s) of Transporter's system and Shipper's system specified in Shipper's Transportation Service Agreement. Shipper may use alternate delivery points within Shipper's Transportation Path on a secondary basis for deliveries to storage.

4.3 Pressures: Shipper shall deliver gas to Transporter at pressure required from time to time to enable the gas to enter Transporter's facilities at the Receipt Point(s). Transporter shall deliver gas to Shipper or Shipper's designee at Transporter's line pressures existing at the Delivery Point(s).

RATE SCHEDULE FT-GS
SMALL CUSTOMER TRANSPORTATION SERVICE (continued)

5. RATES AND CHARGES

5.1 Applicable Rates: The applicable rates for service hereunder in each zone are set forth in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff and are incorporated herein; provided, however, that upon notice to Shipper, Transporter has the right at any time and from time to time to adjust the rates applicable to service under this Rate Schedule to any level not less than the minimum nor more than the maximum rates established for this Rate Schedule and set forth in the Summary of Rates and Charges in Transporter's FERC Gas Tariff. Unless Transporter and Shipper agree upon a rate for service provided hereunder, the rate applicable for service hereunder shall be the applicable Maximum Rate(s) as set forth in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff. In the event a rate less than the applicable Maximum Rate(s) and not less than the applicable Minimum Rate(s) is agreed upon, such rate (a) shall apply solely to service at receipt and/or delivery points agreed upon by Transporter, and (b) shall be applicable for the period agreed upon by Transporter. By mutual agreement between Transporter and Shipper, discounts may be limited consistent with the provisions of Section 6.1 of the pro forma service agreement applicable to this Rate Schedule FT-GS. In the event Transporter and Shipper agree to a fixed rate for service provided hereunder and which is to be charged for the duration of the Service Agreement, said rate will be set forth in the applicable Service Agreement. Transporter shall file with the Commission the required reports of any adjustment below the maximum rates for service under this Rate Schedule.

5.2 Facilities Charge: In addition to the other charges pursuant to Section 5.1 of this Rate Schedule, Transporter may charge Shipper an amount to reflect the cost of Tap Facilities or Tap and Connecting Facilities as provided in Article XIX of the General Terms and Conditions of Transporter's FERC Gas Tariff; provided, however, that if new facilities are necessary solely to enable Transporter to maintain existing service levels, then no Facilities Charge will be assessed. Any applicable Facilities Charge may be stated in the Transportation Service Agreement.

5.3 Incidental Charges: In addition to the charges pursuant to Sections 5.1 and 5.2 of this Rate Schedule, Transporter shall charge Shipper an amount to recoup any filing or similar fees which Transporter incurs in rendering service hereunder, which have not been previously paid by Shipper. Transporter shall not use the amounts so collected either as revenues or costs in establishing its general system rates. The applicable Incidental Charges shall be stated in the Transportation Service Agreement.

5.4 Authorized Overrun Charge: If Shipper, upon receiving the advance approval of Transporter through Transporter's Interactive Website, should on any day take under this Rate Schedule a quantity of natural gas more than Shipper's maximum daily quantity under Shipper's Transportation Service Agreement then such quantity shall constitute an Authorized Overrun.

NAESB Standard 1.3.19 states: Overrun quantities should be requested on a separate transaction. Therefore, all Shipper requests for Authorized Overruns must be nominated through Transporter's Interactive Website.

If Transporter has complete and unrestricted control over gas deliveries to Shipper, Shipper shall be deemed to have received the advance approval of Transporter for such excess takes. For all such Authorized Overruns, Shipper shall pay Transporter the rate set forth in the Summary of Rates and Charges in Transporter's FERC Gas Tariff, unless the parties mutually agree otherwise.

RATE SCHEDULE FT-GS
SMALL CUSTOMER TRANSPORTATION SERVICE (continued)

5. RATES AND CHARGES (continued)

5.5 Fuel and Losses: Shipper shall furnish the quantity of gas required for Fuel and Losses associated with rendering transportation service pursuant to this Rate Schedule. The quantity of gas retained by Transporter for Fuel and Losses shall be equal to the quantity of gas scheduled for delivery to Transporter multiplied by the applicable F&LR percentage shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff for the receipt and delivery zones applicable to the transportation service; provided however, upon Transporter's determination, for service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall furnish only that quantity of gas associated with Losses as shown in the Summary of Rates and Charges in Transporter's FERC Gas Tariff.

In addition, Shipper shall pay Transporter the applicable EPCR Component of the Fuel Adjustment Mechanism, shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff for the zone of receipt and zone of delivery applicable to the transportation service multiplied by the volume of gas scheduled for delivery by Transporter.

5.6 Notwithstanding any provision of Transporter's effective FERC Gas Tariff to the contrary, Transporter and Shipper may mutually agree in writing to rates, rate components, charges, or credits for service under this Rate Schedule that differ from those rates, rate components, charges, or credits that are otherwise prescribed, required, established or imposed by this Rate Schedule or by any other applicable provision of Transporter's effective FERC Gas Tariff. If Transporter agrees to such differing rates, rate components, charges, or credits (referred to hereinafter and in this Tariff as "Negotiated Rates"), then the Negotiated Rate[s] shall be effective only for the period agreed upon by Transporter. During such period, the Negotiated Rate shall govern and apply to the Shipper's service and the otherwise applicable rate, rate component, charge, or credit, which the parties have agreed to replace with the Negotiated Rate, shall not apply to, or be available to, the Shipper. At the end of such period, the otherwise applicable maximum rates or charges shall govern the service provided to Shipper. Only those rates, rate components, charges, or credits identified by Transporter and Shipper in writing as being superseded by a Negotiated Rate shall be ineffective during the period that the Negotiated Rate is effective; all other rates, rate components, charges, or credits prescribed, required, established or imposed by this Rate Schedule or Transporter's Tariff shall remain in effect. Transporter shall make any filings at the FERC necessary to effectuate a Negotiated Rate.

6. MONTHLY BILL

The Monthly Bill for deliveries shall be equal to:

(a) The Commodity Rate, as determined pursuant to Section 5.1 herein multiplied by the quantity of gas scheduled for delivery to the Shipper's city gate in the month; and
(b) The fuel and loss adjustment pursuant to Section 5.5; and

(c) If applicable, any New Facilities Charge, any Incidental Charges, any Authorized Overrun Charges; and.

(d) Any applicable surcharges as shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff.

7. MONTHLY SCHEDULING AND BALANCING

Shippers receiving FS service from Transporter may elect to use that service in conjunction with service under this Rate Schedule to effect load balancing. These Shippers shall provide Transporter, five days prior to the beginning of the month, a projection of the average daily load of gas to be transported under this Rate Schedule on each day in the following month. To the extent that Shipper's actual load is above or below the projected amount for a given day, Transporter shall schedule for withdrawal or injection, as applicable, the corresponding amount of gas from Shipper's Storage account. Such adjustment to Shipper's storage account shall be done automatically, unless otherwise specified in instructions provided by Shipper or Shipper's agent. For Customers making this election, this Rate Schedule shall be the exclusive service for deliveries into and out of storage. Shippers will not be subject to the Daily Variance provisions of Rate Schedule LMS-MA if they have elected to utilize the contract storage service as provided in this Section 7.

RATE SCHEDULE FT-GS
SMALL CUSTOMER TRANSPORTATION SERVICE (continued)

8. GENERAL TERMS AND CONDITIONS

Shipper shall provide Transporter the information as is needed to meet the requirements placed on Transporter pursuant to 18 C.F.R Part 284. The General Terms and Conditions specified in Volume 1 of Transporter's FERC Gas Tariff are incorporated as part of this Rate Schedule.

RATE SCHEDULE FT-IL
FIRM TRANSPORTATION INCREMENTAL LATERAL SERVICE

1. AVAILABILITY

This Rate Schedule is available for the transportation of natural gas on a firm basis by Tennessee Gas Pipeline Company, L.L.C. (Transporter) for any Shipper on Incremental Lateral facilities that are identified under Article XX, Section 2 of the General Terms and Conditions and identified in Shipper's Incremental Lateral Transportation Service Agreement ("FT-IL Service Agreement");

(a) which has submitted a valid request for service pursuant to Article XXVI of the General Terms and Conditions;

(b) which has executed a FT-IL Service Agreement wherein Transporter agrees to transport natural gas for Shipper's account up to a specific maximum daily Transportation Quantity; and

(c) which has caused its supplier of gas, if such supplier has retained processing rights to the gas delivered to Shipper, to enter into a Transportation Contract for the transportation of any liquids and any PTR quantities associated with the processing of gas received at the Receipt Point(s) under Shipper's FT-IL Service Agreement.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Firm transportation service under this Rate Schedule shall be provided (i) to the extent Transporter determines firm capacity is available, and (ii) if Shipper has satisfied the requirements of Articles IV and XXVI of the General Terms and Conditions; provided, however, Transporter shall not commence service until Transporter and Shipper have executed a FT-IL Service Agreement. Shipper shall have the right to enter into one or more transportation contracts for the service provided under this Rate Schedule.

2.2 Transporter shall not be required to install, operate or maintain any additional facilities in order to provide transportation service under this Rate Schedule.

2.3 Transporter shall not be required to transport gas where the total quantity of gas scheduled for transportation is less than that required to operate existing compression facilities necessary to provide the transportation service.

3. QUALIFICATION FOR SERVICE

3.1 All Shippers requesting firm lateral transportation service must qualify pursuant to Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff.

3.2 All Shippers requesting firm lateral transportation service must execute a FT-IL Service Agreement in accord with the provisions of Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff.

4. DELIVERY AND RECEIPT POINTS; PRESSURE; UNIFORM QUANTITIES

4.1 Primary Receipt Points: Subject to the availability of capacity, Transporter shall receive from Shipper, or for the account of Shipper, at those point(s) on the Incremental Lateral identified in the FT-IL Service Agreement between Shipper and Transporter for transportation of daily quantities of gas. Transporter shall not be required under any circumstances to receive gas at any Receipt Point where the total quantity of gas for transportation scheduled for receipt on any day is less than that required for the accurate measurement of quantities to be received. Shipper's specific TQ shall be a uniform quantity throughout the term of the Transportation Service Agreement, except that Transporter may, on a not unduly discriminatory basis, agree to varying levels in Shipper's TQ over specified periods. Shipper's TQ and any varying levels in TQ, as well as the period of such varying TQ levels, shall be specified in the Transportation Service Agreement. The TQ shall be a uniform quantity throughout any month.

4.2 Secondary Receipt Points: All receipt points on the lateral identified in Shipper's FT-IL Service Agreement shall be available as Secondary Receipt Points up to the maximum daily quantity that is applicable to the Primary Receipt Points in Shipper's Transportation Path.

4.3 Primary Delivery Points: Subject to availability of capacity any delivery point on the Incremental Lateral identified in Shipper's FT-IL Service Agreement that is covered by a Balancing Agreement ("eligible delivery point") shall be eligible to be designated in Shipper's FT-IL Service Agreement as a Primary Delivery Point for gas transported by Transporter under this Rate Schedule.

RATE SCHEDULE FT-A
FIRM TRANSPORTATION SERVICE

1. AVAILABILITY

This Rate Schedule is available for the transportation of natural gas on a firm basis by Tennessee Gas Pipeline Company, L.L.C. (Transporter) for any Shipper:

(a) which has executed a Transportation Contract wherein Transporter agrees to transport natural gas for Shipper's account up to a specific maximum daily Transportation Quantity; and

(b) which has caused its supplier of gas, if such supplier has retained processing rights to the gas delivered to Shipper, to enter into a Transportation Contract for the transportation of any liquids and any PTR quantities associated with the processing of gas received at the Receipt Point(s) under Shipper's Transportation Contract after August 1, 1992.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Firm transportation service under this Rate Schedule shall be provided (i) to sales customers which have converted their firm sales entitlement to firm transportation service, (ii) to firm transportation customers who have converted their firm service under other rate schedules to service under this Rate Schedule, (iii) to the extent Transporter determines firm capacity is available, and (iv) if Shipper has satisfied the requirements of Articles IV and XXVI of the General Terms and Conditions; provided, however, Transporter shall not commence service until Transporter and Shipper have executed a Transportation Contract. Shipper shall have the right to enter into one or more transportation contracts for the service provided under this Rate Schedule.

2.2 Transporter shall not be required to install, operate or maintain any additional facilities in order to provide transportation service under this Rate Schedule.

2.3 Transporter shall not be required to transport gas where the total quantity of gas scheduled for transportation is less than that required to operate existing compression facilities necessary to provide the transportation service.

3. QUALIFICATION FOR SERVICE

3.1 All Shippers requesting firm transportation service must qualify pursuant to Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff.

3.2 All Shippers requesting firm transportation service must execute a Transportation Service Agreement in accord with the provisions of Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff.

4. DELIVERY AND RECEIPT POINTS; PRESSURE; UNIFORM QUANTITIES

4.1 Primary Receipt Points: Subject to the availability of capacity, any receipt point on Transporter's system, including storage service points and Pooling Area Points, shall be eligible for designation as a Primary Receipt Point for gas transported under this Rate Schedule. Transporter shall not be required under any circumstances to receive gas at any Receipt Point where the total quantity of gas for transportation scheduled for receipt on any day is less than that required for the accurate measurement of quantities to be received. Shipper's specific TQ shall be a uniform quantity throughout the term of the Transportation Service Agreement, except that Transporter may, on a not unduly discriminatory basis, agree to varying levels in Shipper's TQ over specified periods. Shipper's TQ and any varying levels in TQ, as well as the period of such varying TQ levels, shall be specified in the Transportation Service Agreement. The TQ shall be a uniform quantity throughout any month. With regard to Transportation Contracts entered into after June 25, 1991, Shipper shall be required to notify Transporter if both (i) a Shipper does not deliver gas at a Primary Receipt Point that is capacity constrained at an average daily quantity greater than 30% of Shipper's maximum daily quantity at that receipt point under Shipper's Transportation Contract under this Rate Schedule over any twelve calendar month period and (ii) the Shipper does not have a gas supply contract at that point which has demand, take-or-pay, deficiency or other fixed charge obligations.

Upon receipt of such notice, (i) Shipper's Transportation Contract will then be amended to reduce the maximum daily delivery quantity at that Primary Receipt Point to an amount equal to 10/3 of the average daily deliveries at such point for such twelve calendar month period and (ii) Transporter shall post on its Interactive Website the availability of that point for Primary Receipt Point designations. Shipper will be able to designate a replacement Primary Receipt Point on the same Supply Leg.

RATE SCHEDULE FT-A
FIRM TRANSPORTATION SERVICE (continued)

4. DELIVERY AND RECEIPT POINTS; PRESSURE; UNIFORM QUANTITIES (continued)

4.2 Secondary Receipt Points: All receipt points on Transporter's system within Shipper's Transportation Path shall be available as Secondary Receipt Points up to the maximum daily quantity that is applicable to the Primary Receipt Points in Shipper's Transportation Path.

4.3 Primary Delivery Points: Subject to availability of capacity any delivery point on Transporter's system, including Pooling Area Points, that is covered by a Balancing Agreement ("eligible delivery point") shall be eligible for designation in Shipper's transportation agreement as a Primary Delivery Point for gas transported by Transporter under this Rate Schedule.

4.4 Secondary Delivery Points: A Shipper under this rate schedule may use as a Secondary Delivery Point any eligible delivery point on Transporter's system which is within the Transportation Path.

4.5 Contract Quantities at Delivery Points: Except as allowed by Section 4.6, the sum of the maximum daily delivery quantities applicable to all of a Shipper's Primary Delivery Points may not exceed the maximum daily quantity under the Shipper's Transportation Agreement.

4.6 Grandfathered Delivery Point Capacity: A Shipper which was receiving firm sales or transportation service on the day prior to the effective date of Fifth Revised Vol. No. 1 of this tariff may transfer to a new agreement the delivery point capacity and delivery point pressures stated in its former firm sales or transportation service agreement; the Shipper shall be allowed to divide that stated capacity among one or more new agreements so that the total aggregate delivery point capacity is preserved.

4.7 Change of Primary Points: Subject to agreement by Transporter and in accordance with Article XXVI of the General Terms and Conditions of Transporter's FERC Gas Tariff, a Shipper may elect to substitute new points for the Primary Delivery or Primary Receipt Points in its Transportation Service Agreement. Such changes may be affected by prior notice to Transporter of 30 days if in writing or 15 days if via Transporter's Interactive Website. All such changes must be reflected in an amended Transportation Service Agreement and shall be effective at the commencement of the following month unless otherwise agreed by Transporter. Transporter shall not be required to accept an amendment if there is inadequate capacity available to render the new service or if the change would reduce the reservation charges applicable to the Transportation Service Agreement.

4.8 Extended Receipts: Shipper may use points not in its Transportation Path as defined in Section 26 of Article I of the General Terms and Conditions subject to the priority specified in Section 3 of Article IV of the General Terms and Conditions. In order to use such points, Shipper must request Extended Receipt Service by designating the Extended Receipt Service zone from which Shipper desires to extend service ("Extension Zone") and nominating in Transporter's Interactive Website the following information: (i) the point at which Shipper desires to receive gas ("Extended Receipt Point") and (ii) the requested quantity to be received at the point. Termination of the underlying agreement shall terminate any Extended Receipt Service. This service will be subject to an additional usage charge from the Extension Zone to the Extended Zone containing the Extended Receipt Point as specified in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff.

4.9 Extended Deliveries: Shipper may use points not in its Transportation Path as defined in Section 26 of Article I of the General Terms and Conditions subject to the priority specified in Section 3 of Article IV of the General Terms and Conditions. In order to use such points, Shipper must request Extended Delivery Service by designating the Extended Delivery Service zone from which Shipper desires to extend service ("Extension Zone") and nominating in Transporter's Interactive Website the following information: (i) the point at which Shipper desires to deliver gas ("Extended Delivery Point") and (ii) the requested quantity to be delivered at the point. Termination of the underlying agreement shall terminate any Extended Delivery Service. This service shall be subject to an additional usage charge from the Extension Zone to the Extended Zone containing the Extended Delivery Point as specified in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff.

RATE SCHEDULE FT-A
FIRM TRANSPORTATION SERVICE (continued)

4. DELIVERY AND RECEIPT POINTS; PRESSURE; UNIFORM QUANTITIES (continued)

4.10 Pressures: Shipper shall deliver gas to Transporter at the pressure required from time to time to enable the gas to enter Transporter's facilities at the Receipt Point(s). Transporter shall deliver gas to Shipper or Shipper's designee at Transporter's line pressure existing at the Delivery Point(s).

4.11 Uniform Quantities: As nearly as practicable, Shipper shall deliver and receive gas in uniform hourly quantities during any day. Subject to Transporter's operating conditions, during any given day Transporter will allow Shipper to deliver or receive gas at an hourly rate that may exceed 1/24th of Shipper's scheduled quantities.

5. RATES AND CHARGES

5.1 Applicable Rates: The applicable rates for service under the FT-A Rate Schedule are the applicable maximum FT-A rates shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff; provided, however, upon notice to Shipper, Transporter has the right at any time and from time to time to adjust the rates applicable to any transportation service to any level not less than the minimum or more than the maximum rates established for this Rate Schedule and set forth in the Summary of Rates and Charges of Transporter's effective FERC Gas Tariff. In the event that Transporter makes such an adjustment, such adjusted rates (a) shall apply solely to service at the receipt and/or delivery points agreed upon by Transporter, and (b) shall be applicable for the period agreed upon by Transporter. By mutual agreement between Transporter and Shipper, discounts may be limited consistent with the provisions of Section 6.1 of the pro forma service agreement applicable to this Rate Schedule FT-A.

In the event the Shipper has designated multiple Primary Receipt and/or Delivery points, a Weighted Average Reservation Rate shall be applied to the total maximum daily transportation quantity specified in the Transportation Service Agreement; provided, however, that the addition of points to a Transportation Service Agreement shall not reduce the reservation charge otherwise applicable to the Transportation Service Agreement. The Weighted Average Reservation Rate shall be determined as follows: (1) for each Primary Receipt and Primary Delivery point combination available under the Transportation Service Agreement the applicable Reservation Rate shall be multiplied by the maximum daily transportation quantity applicable to that receipt and delivery point combination; (2) the sum of the amounts derived for each receipt and delivery point combination shall be divided by the total maximum daily transportation quantity specified in the Transportation Service Agreement. The sum of the maximum daily transportation quantities applicable to each receipt and delivery point combination shall not exceed the total maximum daily transportation quantity under the Transportation Service Agreement. In the event Transporter and Shipper agree to establish a fixed rate to be charged for the duration of the firm Transportation Service Agreement, said rate will be set forth in the Service Agreement. Transporter shall file with the Commission the required reports of any adjustment below the maximum Commodity and/or Reservation Rates for service under this Rate Schedule.

5.2 Facilities Charge: In addition to the other charges pursuant to Section 5.1 of this Rate Schedule, Transporter may charge Shipper an amount to reflect the cost of Tap Facilities or Tap and Connecting Facilities as provided in Article XIX of the General Terms and Conditions of Transporter's FERC Gas Tariff; provided, that if new facilities are necessary solely to enable Transporter to maintain existing service levels for Shipper, then no Facilities Charge will be assessed. Any applicable Facilities Charge may be stated in the Transportation Service Agreement.

5.3 Incidental Charges: In addition to the charges pursuant to Sections 5.1 and 5.2 of this Rate Schedule, Transporter shall charge Shipper an amount to recoup any filing or similar fees which Transporter incurs in rendering service hereunder, which have not been previously paid by Shipper. Transporter shall not use the amounts so collected either as revenues or costs in establishing its general system rates. The applicable Incidental Charges shall be stated in the Transportation Service Agreement.

RATE SCHEDULE FT-A
FIRM TRANSPORTATION SERVICE (continued)

5. RATES AND CHARGES (continued)

5.4 Authorized Overrun Charge: If Shipper, upon receiving the advance approval of Transporter through Transporter's Interactive Website, should on any day take under this Rate Schedule a quantity of natural gas more than Shipper's maximum daily quantity under Shipper's Transportation Service Agreement, then such quantity shall constitute an Authorized Overrun. If Transporter has complete and unrestricted control over gas deliveries to Shipper, Shipper shall be deemed to have received the advance approval of Transporter for such excess takes.

NAESB Standard 1.3.19 states: Overrun quantities should be requested on a separate transaction. Therefore, all Shipper requests for Authorized Overruns must be nominated through Transporter's Interactive Website.

For all such Authorized Overruns, Shipper shall pay Transporter the rate set forth in the Summary of Rates and Charges of Transporter's FERC Gas Tariff times the excess quantities delivered to Shipper, unless the parties mutually agree otherwise.

5.5 Fuel and Losses. Shipper shall furnish the quantity of gas required for Fuel and Losses associated with rendering transportation service pursuant to this Rate Schedule. The quantity of gas retained by Transporter for Fuel and Losses shall be equal to the quantity of gas scheduled for delivery to Transporter multiplied by the applicable F&LR percentage shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff for the zone of receipt and zone of delivery applicable to the transportation service. However, for service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall furnish only that quantity of gas associated with Losses as shown in the Summary of Rates and Charges in Transporter's FERC Gas Tariff.

In addition, Shipper shall pay Transporter the applicable EPCR Component of the Fuel Adjustment Mechanism, shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff for the zone of receipt and zone of delivery applicable to the transportation service multiplied by the volume of gas scheduled for delivery by Transporter.

5.6 Notwithstanding any provision of Transporter's effective FERC Gas Tariff to the contrary, Transporter and Shipper may mutually agree in writing to rates, rate components, charges, or credits, for service under this Rate Schedule that differ from those rates, rate components, charges, or credits, that are otherwise prescribed, required, established or imposed by this Rate Schedule or by any other applicable provision of Transporter's effective FERC Gas Tariff. If Transporter agrees to such differing rates, rate components, charges, or credits (referred to hereinafter and in this Tariff as "Negotiated Rates"), then the Negotiated Rate[s] shall be effective only for the period agreed upon by Transporter. During such period, the Negotiated Rate shall govern and apply to the Shipper's service and the otherwise applicable rate, rate component, charge, or credit, which the parties have agreed to replace with the Negotiated Rate, shall not apply to, or be available to, the Shipper. At the end of such period, the otherwise applicable maximum rates or charges shall govern the service provided to Shipper. Only those rates, rate components, charges, or credits, identified by Transporter and Shipper in writing as being superseded by a Negotiated Rate shall be ineffective during the period that the Negotiated Rate is effective; all other rates, rate components, charges, or credits prescribed, required, established or imposed by this Rate Schedule or Transporter's Tariff shall remain in effect. Transporter shall make any filings at the FERC necessary to effectuate a Negotiated Rate.

RATE SCHEDULE FT-A
FIRM TRANSPORTATION SERVICE (continued)

6. MONTHLY BILL

The Monthly Bill for deliveries shall be equal to:

(a) Reservation Charge: A reservation charge equal to the product of the applicable Reservation Rate (or Weighted Reservation Rate) shown in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff multiplied by the Transportation Quantity specified in the Transportation Service Agreement; and

(b) Commodity Charge: The applicable Commodity Rate set forth in the Summary of Rates and Charges in Transporter's effective FERC Gas Tariff multiplied by the quantity of gas scheduled in the month; and

(c) Other Charges: If applicable, any New Facilities Charge, any Incidental Charges, any Authorized Overrun Charges, any Fuel and Losses Charge, and any applicable surcharges as shown in the Summary of Rates and Charges and any cash out charges resulting from imbalances incurred.

7. FAILURE OF TRANSPORTER

If Transporter fails to tender for delivery or schedule the quantity of natural gas nominated by Shipper for delivery from a primary Receipt Point to a primary Delivery Point during any one or more days up to the maximum quantity of gas which Transporter is obligated to deliver to Shipper, Transporter shall provide reservation charge credits, if any, as provided in Article XII, Section 5 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

8. GENERAL TERMS AND CONDITIONS

Shipper shall provide Transporter with such information as is needed to meet the requirements placed on Transporter pursuant to 18 CFR Part 284. The General Terms and Conditions specified in Volume 1 of Transporter's FERC Gas Tariff are incorporated as part of this Rate Schedule.

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

September 29, 1994

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 2 to
Gas Transportation Agreement
Dated September 1st, 1993
Service Package No. 2747

Dear George:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, agree to amend the Agreement effective March 1st, 1994, to change the Primary Meters and the associated Meter Quantities as reflected in the Attached Revised Exhibit A-1.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713) 757-3720.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

GP Jallans

Gregory P. Jallans, Account Manager
Central Region

ACCEPTED AND AGREED TO
This 5th Day of October, 1994

DELTA NATURAL GAS COMPANY INC

By: Alan C. Heath

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 6th Day of April, 1995

TENNESSEE GAS PIPELINE COMPANY

By: [signature] GPJ
Director, Transportation Services
Central Region

GAS TRANSPORTA ON REEMENT

EXHIBIT "A"
AMENDMENT #2 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

NATURAL GAS COMPANY INC
TIVE DATE OF AMENDMENT: March 1, 1994
SCHEDULE: FT-A
CE PACKAGE: 2747
CE PACKAGE TQ: 1,400 Dth

	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ
)7	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	39	39
15	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	100	100
54	UNITED-MONROE DEHYD TRANS	KOCH GATEWAY PIPELINE COMPANY	OUACHITA	LA	01	R	100	98	98
57	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	35	35
19	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	234	234
27	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	31	31
47	BIG-BEECH FORK DEHYD		WAYNE	WV	03	R	087	157	157
24	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	49	49
71	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	302	302
13	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	159	159
20	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	196	196
					Total Receipt TQ:			1,400	1,400
48	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	1,400	1,400
					Total Delivery TQ:			1,400	1,400

ER OF RECEIPT POINTS: 12
ER OF DELIVERY POINTS: 1

te: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

(For Use Under G R-te Schedule)
(EXHIBIT "A" t.)

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	12
744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	12
785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	12
020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1,128	0	12
				Total Receipt TQ:				10,044	10,044	
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	190	190	01
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	1,260	1,260	01
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	50	50	01
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	190	190	02
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	1,260	1,260	02
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	50	50	02
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	127	127	03
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	840	840	03
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	33	33	03
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	100	100	04
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	675	675	04
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	25	25	04
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	75	75	05
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	505	505	05
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	20	20	05
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	50	50	06
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	330	330	06
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	20	20	06
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	55	55	07
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	297	297	07
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	20	20	07
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	55	55	08
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	297	297	08
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	20	20	08
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	60	60	09
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	320	320	09
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	20	20	09
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	75	75	10
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	500	500	10
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	25	25	10

(For Use Under G Rate Schedule)
(EXHIBIT A" it.)

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	127	127	11
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	840	840	11
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	33	33	11
0212	DELTA-SALT LICK KY	TENNESSEE GAS MARKETING CO.	BATH	KY	02	D	087	190	190	12
0462	DELTA-FARMERS KY	TENNESSEE GAS MARKETING CO.	ROWAN	KY	02	D	087	1,260	1,260	12
0733	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	50	50	12
							Total Delivery TQ:	10,044	10,044	

IMBER OF RECEIPT POINTS: 15
IMBER OF DELIVERY POINTS: 3

ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

GAS TRANSPORTATION REEMENT

EXHIBIT "A-1"
SHOWING REQUESTED CHANGES
AMENDMENT #2 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

DELTA NATURAL GAS COMPANY INC
EFFECTIVE DATE OF AMENDMENT: March 1, 1994
RATE SCHEDULE: FT-A
SERVICE PACKAGE: 2747
SERVICE PACKAGE TQ: 1,400 Dth

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ
010864	KOCH-MONROE DEHYD TRANS	KOCH GATEWAY PIPELINE COMPANY	OUACHITA	LA	01	R	100	98	98
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	-98	-98
							Total Receipt TQ:	0	0
							Total Delivery TQ:	0	0

NUMBER OF RECEIPT POINTS AFFECTED: 2
NUMBER OF DELIVERY POINTS AFFECTED: 1

Exhibit 1-13

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

OCT 29 1993

October 25, 1993

Delta Natural Gas Company, Inc.
3617 Lexington
Winchester, KY 40391

Attention: George S. Billings

Re: Gas Transportation Agreement
TGP Contract No. T-2747

Dear Mr. Billings:

Enclosed for retention by Delta Natural Gas Company, Inc. is a fully executed original of the Gas Transportation Agreement for the referenced request.

I have enjoyed working with you on your transportation request and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE COMPANY

Greg

Greg Jallans
Sr. Account Executive

Enclosure

cc: Files

TIMELESS
1943 1993

Contract No.: 2747

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-A Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1st day of September, 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

ARTICLE I
DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each year during the term hereof which shall be 1,400 dekatherms (Dth). Any limitations of the quantities to be received from each Point of Receipt and/or delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II
TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III
POINT(S) OF RECEIPT AND DELIVERY

The Primary Point(s) of Receipt and Delivery shall be those points specified on Exhibit A attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V
QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI
RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the date of execution, the rates, charges, and surcharges to be paid by Shipper to Transporter for the transportation service provided herein shall be in accordance with Transporter's Rate Schedule FT-A and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid for by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-A, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter's just and reasonable rates.

ARTICLE VII
BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII
GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-A and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX
REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no party shall be liable to any other party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Part 284, Subpart G of the FERC Regulations.

ARTICLE X
RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI
WARRANTIES

11.1 In addition to the warranties set forth in Article IX of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit A attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty, express or implied, by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII
TERM

12.1 This contract shall be effective as of September 1, 1993, and shall remain in force and effect until November 1,2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to resolve or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1, shall survive the other parts of this Agreement until such time as such balancing has been accomplished;

12.3 This Agreement will terminate upon notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII
NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the party intended to receive the same, as follows:

TRANSPORTER: Tennessee Gas Pipeline Company
P. O. Box 2511
Houston, Texas 77252-2511

Attention: Transportation Marketing

SHIPPER:

NOTICES: Delta Natural Gas Company, Inc.
3617 Lexington Rd.
Winchester, KY 40391

Attention: George S. Billings

BILLING: Delta Natural Gas Company, Inc.
3617 Lexington Rd.
Winchester, KY 40391

Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

Bsr

ARTICLE XIV
ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Either Party may, without relieving itself of its obligation under this Agreement, assign any of its rights hereunder to a company with which it is affiliated, otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV
MISCELLANEOUS

15.1 The interpretation and performance of this contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this agreement shall be or become effective, except by the execution of by both Parties of a written amendment.

15.4 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

BY: ______________________
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

BY: ______________________
George S. Billings

TITLE: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2747

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-A Rate Schedule)

EXHIBIT "A"
TO GAS TRANSPORTATION AGREEMENT
DATED September 1st, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

SERVICE PACKAGE: 2747

SERVICE PACKAGE TQ: 1,400

METER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ
000807	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	39
010215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	100
011057	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	35
011119	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	234
011127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	31
011347	0	BIG-BEECH FORK DEHYD		WAYNE	WV	03	R	087	157
011624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	49
011971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	302
012013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	159
012020	0	TRANSCO - FALFURRIAS TRANSPORT	TRANSCONTINENTAL GAS PIPE LINE	JIM WELLS	TX	00	R	100	196
020741	0	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	98
020248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	1,400

NUMBER OF RECEIPT POINTS: 11
NUMBER OF DELIVERY POINTS: 1

Exhibit 1-14

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
TELEPHONE 606-744-6171
FAX 606-744-3623

August 25, 1993

Mr. Albert M. Baker
Tennessee Gas Marketing Company
1100 Louisiana Street
P. O. Box 2511
Houston, Texas 77252-2511

Dear Al:

Enclosed for your records are copies of the FT-G, FT-A and FS contracts with Tennessee Gas Pipeline Company which have been signed and returned by Delta Natural Gas Company, Inc. Delta has four (4) service agreements with TGP for six (6) points of delivery which are now being replaced by four (4) FT-G agreements, one (1) FT-A agreement, three (3) FS market area storage agreements, and two (2) FS production area storage agreements.

I have also enclosed copies of the cover letters which accompanied the agreements. You can tell from the letter sent with the FS agreements that TGP has changed their March 1993 storage allocation for Delta, with more capacity shifted to the production area storage (Bear Creek) and less to the market area storage (Lost Creek).

If you have any questions or desire additional information, please give me a call.

Sincerely,

George S. Billings

George S. Billings
Manager - Gas Supply

Enclosures

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
TELEPHONE 606-744-6171
FAX 606-744-3623

August 24, 1993

VIA FEDERAL EXPRESS

Mr. Gregory P. Jallans, Sr. Account Executive
Tennessee Gas Pipeline
Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511

Dear Greg:

Enclosed are duplicate originals of the following contracts:

TGP FT-A Contract No. 2747
TGP FT-G Contract No. 2515
TGP FT-G Contract No. 2516
TGP FT-G Contract No. 2555
TGP FT-G Contract No. 2448

These agreements have been executed by Delta Natural Gas Company, Inc. Please note the change to Paragraph 12.2 on page 5 of each of the agreements. This change was made so the agreements would conform to TGP's pro forma FT-G and FT-A agreements in the July 23, 1993 compliance filing. Paragraph 15.3 of each agreement also does not comply with the tariff, but the language in the agreement is acceptable without modification.

Upon execution by Tennessee, please return one fully executed original of each agreement to my attention.

Sincerely,

George S. Billings
George S. Billings
Manager - Gas Supply

Enclosures

Tennessee Gas Pipeline
A Tenneco Company

1010 Milam Street
P.O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

APR 17 1995
RECEIVED

April 11, 1995

Delta Natural Gas Company Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797

Attention: Mr. George S. Billings

Re: Gas Transportation Agreements
Service Package No.'s:
2448, Amendment No. 1
2516, Amendment No. 1
2555, Amendment No. 1
2747, Amendment No.'s 2 & 3

Dear George:

Enclosed for retention are fully executed sets of the Gas Transportation Agreements for the referenced requests.

I have enjoyed working with you on your transportation requests and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE

Greg

Gregory P. Jallans
Account Manager

/jln

Enclosure

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

April 4, 1995

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 3 to
Gas Transportation Agreement
Dated September 1, 1993
Service Package No. 2747

Dear George:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, agree to amend the Agreement effective March 1, 1994 through (term. date) to allow TENNESSEE GAS MARKETING CO. to act as agent for DELTA NAT GAS, in accordance with section 14.3 of Article III in the General Terms and conditions of Tennessee's effective FERC Gas Tariff, for the capacity listed in Exhibit A-1. The remaining Primary Capacity for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-3720.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

GJallans

Greg Jallans, Account Manager

ACCEPTED AND AGREED TO
This 6th Day of April, 1995

TENNESSEE GAS PIPELINE COMPANY

By: [signature]

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 31st Day of OCTOBER, 1994

DELTA NATURAL GAS COMPANY INC

By: Alan L. Heath

Title: V.P. OPS. & ENG.

GAS TRANSPOR... AGREEMENT

EXHIBIT "A"
AMENDMENT #3 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

DELTA NATURAL GAS COMPANY INC
EFFECTIVE DATE OF AMENDMENT: March 1, 1994
RATE SCHEDULE: FT-A
SERVICE PACKAGE: 2747
SERVICE PACKAGE TQ: 1,400 Dth

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	39	0
010215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	100	0
010864	UNITED-MONROE DEHYD TRANS	KOCH GATEWAY PIPELINE COMPANY	OUACHITA	LA	01	R	100	98	0
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	35	0
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	234	0
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	31	0
011347	BIG-BEECH FORK DEHYD		WAYNE	WV	03	R	087	157	157
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	49	0
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	302	0
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	159	0
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	196	0
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	98
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	259
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	651
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	235
							Total Receipt TQ:	1,400	1,400
020248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	1,400	1,400
							Total Delivery TQ:	1,400	1,400

NUMBER OF RECEIPT POINTS: 15
NUMBER OF DELIVERY POINTS: 1

Note: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

GAS TRANSPORTATION AGREEMENT

EXHIBIT "A-1"
SHOWING REQUESTED CHANGES
AMENDMENT #3 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

DELTA NATURAL GAS COMPANY INC
EFFECTIVE DATE OF AMENDMENT: March 1, 1994
RATE SCHEDULE: FT-A
SERVICE PACKAGE: 2747
SERVICE PACKAGE TQ: 1,400 Dth
SERVICE PACKAGE MSQ: 0

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-39
010215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-100
010864	UNITED-MONROE DEHYD TRANS	KOCH GATEWAY PIPELINE COMPANY	OUACHITA	LA	01	R	100	0	-98
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-35
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-234
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-31
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-49
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-302
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-159
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-196
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	98
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	259
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	651
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	235

Total Receipt TQ: 0 0

Total Delivery TQ: 0 0

NUMBER OF RECEIPT POINTS: 14
NUMBER OF DELIVERY POINTS: 0

Exhibit 1-15

Tennessee Gas Pipeline
A Tenneco Company

1010 Milam Street
P.O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

APR 1 7 1995
RECEIVED

April 11, 1995

Delta Natural Gas Company Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797

Attention: Mr. George S. Billings

Re: Gas Transportation Agreements
Service Package No.'s:
2448, Amendment No. 1
2516, Amendment No. 1
2555, Amendment No. 1
2747, Amendment No.'s 2 & 3

Dear George:

Enclosed for retention are fully executed sets of the Gas Transportation Agreements for the referenced requests.

I have enjoyed working with you on your transportation requests and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE

Greg

Gregory P. Jallans
Account Manager

/jln

Enclosure

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

April 4, 1995

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 1 to
Gas Transportation Agreement
Dated September 1, 1993
Service Package No. 2555

Dear George:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, agree to amend the Agreement effective January 1, 1994 through (term. date) to allow TENNESSEE GAS MARKETING CO. to act as agent for DELTA NAT GAS, in accordance with section 14.3 of Article III in the General Terms and conditions of Tennessee's effective FERC Gas Tariff, for the capacity listed in Exhibit A-1. The remaining Primary Capacity for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713) 757-3720.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

Greg Jallans, Account Manager

ACCEPTED AND AGREED TO
This 31st Day of October, 1994

DELTA NATURAL GAS COMPANY INC

By: ______________________________

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This ~~31st~~ 6th Day of ~~October~~ April, ~~1994~~ 1995

TENNESSEE GAS PIPELINE COMPANY

By: ______________________________

Title: Agent and Attorney in Fact

(For Use Under 1 } Rate Schedule)

EXHIBIT "A
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

.TA NATURAL GAS COMPANY INC
FECTIVE DATE OF AMENDMENT: January 1, 1994
TE SCHEDULE: FT-G
RVICE PACKAGE: 2555

NTHLY MDQS:	(01) January	8,561	(04) April	4,000	(07) July	2,000	(10) October	3,644
	(02) February	8,561	(05) May	2,800	(08) August	2,000	(11) November	5,000
	(03) March	5,600	(06) June	2,000	(09) September	2,000	(12) December	8,561

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	01
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	01
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	01
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	01
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	01
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	01
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	01
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	01
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	01
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	01
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	5,269	01
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	01
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	01
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	01
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	4,917	0	01
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	02
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	02
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	02
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	02
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	02
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	02
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	02
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	02
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	02
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	02
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	5,269	02
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	02
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	02
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	02
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	4,917	0	02
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	03
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	03
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	03

GAS TRANSPORT ON AGREEMENT
(For Use Under F R Schedule)
(EXHIBIT "A" c.)

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	03
119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	03
127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	03
624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	03
971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	03
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	03
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	03
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	2,308	03
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	03
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	03
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	03
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1,956	0	03
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	04
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	04
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	04
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	04
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	04
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	04
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	04
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	04
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	04
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	04
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	708	04
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	04
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	04
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	04
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	356	0	04
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	5	0	05
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	314	314	05
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	200	0	05
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	71	0	05
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	468	0	05
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	61	0	05
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	98	0	05
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	604	0	05
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	317	0	05
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	392	0	05
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	270	270	05
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	517	05
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,302	05
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	397	05
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	3	0	06
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	224	224	06
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	143	0	06
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	50	0	06
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	334	0	06
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	44	0	06

(For Use Under G Rate Schedule)
(EXHIBIT A" t.)

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	70	0	06
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	431	0	06
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	227	0	06
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	280	0	06
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	193	194	06
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	06
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	06
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	06
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1	0	06
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	3	0	07
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	224	224	07
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	143	0	07
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	50	0	07
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	334	0	07
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	44	0	07
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	70	0	07
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	431	0	07
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	227	0	07
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	280	0	07
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	193	194	07
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	07
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	07
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1	0	07
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	3	0	08
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	224	224	08
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	143	0	08
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	50	0	08
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	334	0	08
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	44	0	08
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	70	0	08
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	431	0	08
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	227	0	08
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	280	0	08
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	193	194	08
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	08
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	08
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	08
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1	0	08
10807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	3	0	09
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	224	224	09
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	143	0	09
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	50	0	09
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	334	0	09
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	44	0	09
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	70	0	09
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	431	0	09

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
:013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	227	0	09
:020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	280	0	09
)741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	193	194	09
)743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	09
)744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	09
)785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	09
)020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1	0	09
)807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	10
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	10
)215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	10
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	10
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	10
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	10
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	10
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	10
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	10
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	10
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	352	10
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	10
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	10
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	10
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	11
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	11
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	11
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	11
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	11
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	11
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	11
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	11
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	11
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	11
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	1,708	11
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	11
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	11
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	11
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1,356	0	11
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	6	0	12
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	408	408	12
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	260	0	12
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	92	0	12
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	609	0	12
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	80	0	12
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	128	0	12
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	786	0	12
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	413	0	12
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	510	0	12
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	352	5,269	12

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	12
744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	12
785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	12
020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	4,917	0	12
					Total Receipt TQ:			54,727	54,727	
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	8,561	8,561	01
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	8,561	8,561	02
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	5,600	5,600	03
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	4,000	4,000	04
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	2,800	2,800	05
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	2,000	2,000	06
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	2,000	2,000	07
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	2,000	2,000	08
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	2,000	2,000	09
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	3,644	3,644	10
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	5,000	5,000	11
0248	DELTA-NICHOLASVILLE KY	TENNESSEE GAS MARKETING CO.	GARRARD	KY	02	D	087	8,561	8,561	12
					Total Delivery TQ:			54,727	54,727	

MBER OF RECEIPT POINTS: 15
MBER OF DELIVERY POINTS: 1

ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

GAS TRANSPORTATI(AGREEMENT
(For Use Under FT-G ' :e ' hedule)

EXHIBIT "A-1"
SHOWING REQUESTED CHANGES
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

LTA NATURAL GAS COMPANY INC
FECTIVE DATE OF AMENDMENT: January 1, 1994
TE SCHEDULE: FT-G
RVICE PACKAGE: 2555

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	01
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	01
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	01
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	01
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	01
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	01
.1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	01
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	01
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	01
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	4,917	01
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	01
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	01
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	01
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-4,917	01
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	02
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	02
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	02
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	02
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	02
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	02
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	02
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	02
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	02
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	4,917	02
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	02
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	02
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	02
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-4,917	02
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	03
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	03
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	03
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	03
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	03
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	03
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	03
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	03
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	03
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1,956	03

GAS TRANSPORTATI N AGREEMENT
(For Use Under F1 Ra' Schedule)
(EXHIBIT "A-1" t.)

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	03
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	03
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	03
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1,956	03
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	04
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	04
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	04
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	04
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	04
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	04
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	04
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	04
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	04
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	356	04
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	04
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	04
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	04
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-356	04
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-5	05
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-200	05
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-71	05
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-468	05
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-61	05
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-98	05
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-604	05
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-317	05
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-392	05
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	517	05
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,302	05
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	397	05
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-3	06
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-143	06
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-50	06
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-334	06
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-44	06
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-70	06
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-431	06
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-227	06
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-280	06
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1	06
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	06
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	06
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	06
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1	06
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-3	07
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-143	07
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-50	07

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-334	07
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-44	07
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-70	07
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-431	07
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-227	07
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-280	07
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1	07
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	07
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	07
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1	07
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-3	08
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-143	08
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-50	08
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-334	08
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-44	08
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-70	08
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-431	08
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-227	08
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-280	08
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1	08
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	08
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	08
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	08
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1	08
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-3	09
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-143	09
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-50	09
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-334	09
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-44	09
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-70	09
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-431	09
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-227	09
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-280	09
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1	09
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	370	09
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	929	09
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	283	09
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1	09
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	10
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	10
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	10
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	10
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	10
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	10
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	10
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	10
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	10

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	10
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	10
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	10
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	11
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	11
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	11
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	11
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	11
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	11
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	11
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	11
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	11
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1,356	11
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	11
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	11
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	11
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1,356	11
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-6	12
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-260	12
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-92	12
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-609	12
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-80	12
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-128	12
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-786	12
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-413	12
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-510	12
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	4,917	12
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	673	12
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	1,695	12
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	516	12
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-4,917	12

Total Receipt TQ: 0 0

Total Delivery TQ: 0 0

UMBER OF RECEIPT POINTS: 14
UMBER OF DELIVERY POINTS: 0

Exhibit 1-16

Tennessee Gas Pipeline
A Tenneco Company

1010 Milam Street
P.O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

APR 17 1995
RECEIVED

April 11, 1995

Delta Natural Gas Company Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797

Attention: Mr. George S. Billings

Re: Gas Transportation Agreements
Service Package No.'s:
2448, Amendment No. 1
2516, Amendment No. 1
2555, Amendment No. 1
2747, Amendment No.'s 2 & 3

Dear George:

Enclosed for retention are fully executed sets of the Gas Transportation Agreements for the referenced requests.

I have enjoyed working with you on your transportation requests and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE

Greg

Gregory P. Jallans
Account Manager

/jln

Enclosure

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

April 4, 1995

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 1 to
Gas Transportation Agreement
Dated September 1, 1993
Service Package No. 2516

Dear George:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, agree to amend the Agreement effective January 1, 1994 through (term. date) to allow TENNESSEE GAS MARKETING CO. to act as agent for DELTA NAT GAS, in accordance with section 14.3 of Article III in the General Terms and conditions of Tennessee's effective FERC Gas Tariff, for the capacity listed in Exhibit A-1. The remaining Primary Capacity for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-3720.

Best regards,

Greg Jallans

TENNESSEE GAS PIPELINE COMPANY

Greg Jallans, Account Manager

ACCEPTED AND AGREED TO
This 6th Day of April, 1995

TENNESSEE GAS PIPELINE COMPANY

By: [signature]

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 31st Day of October, 1994

DELTA NATURAL GAS COMPANY INC

By: Alan L. Heath

Title: V.P. OPNS. & ENG.

(For Use Under G Rate Schedule)

EXHIBIT "A"
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ELTA NATURAL GAS COMPANY INC
FFECTIVE DATE OF AMENDMENT: January 1, 1994
ATE SCHEDULE: FT-G
ERVICE PACKAGE: 2516

ONTHLY MDQS:							
(01) January	400	(04) April	200	(07) July	150	(10) October	300
(02) February	400	(05) May	200	(08) August	150	(11) November	300
(03) March	300	(06) June	150	(09) September	250	(12) December	400

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	01
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	01
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	01
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	01
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	01
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	01
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	01
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	01
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	01
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	313	01
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	01
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	01
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	01
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	291	0	01
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	02
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	02
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	02
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	02
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	02
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	02
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	02
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	02
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	02
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	313	02
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	02
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	02
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	02
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	291	0	02
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	03
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	03
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	03
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	03
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	03

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	03
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	03
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	03
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	03
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	213	03
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	03
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	03
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	03
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	191	0	03
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	04
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	04
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	04
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	04
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	04
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	04
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	04
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	04
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	04
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	113	04
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	04
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	04
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	04
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	91	0	04
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	05
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	05
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	05
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	05
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	05
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	05
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	05
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	05
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	05
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	113	05
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	05
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	05
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	05
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	91	0	05
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	06
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	06
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	06
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	06
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	06
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	06
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	06
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	06
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	06
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	63	06

(For Use Under ·G Rate Schedule)
(EXHIBIT "A" ...t.)

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	06
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	06
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	06
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	41	0	06
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	07
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	07
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	07
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	07
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	07
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	07
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	07
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	07
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	07
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	63	07
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	07
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	07
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	41	0	07
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	08
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	08
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	08
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	08
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	08
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	08
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	08
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	08
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	08
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	63	08
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	08
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	08
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	08
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	41	0	08
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	09
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	09
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	09
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	09
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	09
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	09
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	09
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	09
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	09
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	163	09
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	09
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	09
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	09
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	141	0	09

GAS TRANSPOR TION AGREEMENT
(For Use Under -G -te Schedule)
(EXHIBIT "A" nt.)

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	10
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	10
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	10
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	10
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	10
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	10
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	10
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	10
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	10
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	213	10
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	10
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	10
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	10
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	191	0	10
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	11
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	11
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	11
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	11
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	11
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	11
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	11
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	11
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	11
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	213	11
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	11
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	11
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	11
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	191	0	11
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	15	0	12
001347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	11	11	12
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	9	0	12
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	3	0	12
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	17	0	12
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	4	0	12
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	2	0	12
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	14	0	12
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	12	0	12
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	22	313	12
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	12
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	12
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	12
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	291	0	12

Total Receipt TQ: 3,200 3,200

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	400	400	01
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	400	400	02
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	300	300	03
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	200	200	04
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	200	200	05
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	150	150	06
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	150	150	07
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	150	150	08
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	250	250	09
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	300	300	10
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	300	300	11
020430	DELTA-JEFFERSONVILLE KY	TENNESSEE GAS MARKETING CO.	MONTGOMERY	KY	02	D	087	400	400	12
				Total Delivery TQ:				3,200	3,200	

NUMBER OF RECEIPT POINTS: 14
NUMBER OF DELIVERY POINTS: 1

Note: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

GAS TRANSPORTATI AGREEMENT
(For Use Under FT-G .te hedule)

EXHIBIT "A-1"
SHOWING REQUESTED CHANGES
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ELTA NATURAL GAS COMPANY INC
FFECTIVE DATE OF AMENDMENT: January 1, 1994
RATE SCHEDULE: FT-G
SERVICE PACKAGE: 2516

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	01
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	01
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	01
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	01
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	01
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	01
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	01
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	01
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	291	01
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	01
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	01
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	01
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-291	01
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	02
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	02
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	02
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	02
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	02
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	02
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	02
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	02
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	291	02
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	02
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	02
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	02
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-291	02
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	03
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	03
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	03
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	03
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	03
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	03
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	03
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	03
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	191	03
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	03
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	03
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	03

(For Use Under F.   Ra.. Schedule)
(EXHIBIT "A-1"   .t.)

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-191	03
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	04
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	04
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	04
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	04
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	04
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	04
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	04
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	04
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	91	04
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	04
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	04
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	04
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-91	04
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	05
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	05
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	05
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	05
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	05
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	05
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	05
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	05
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	91	05
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	05
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	05
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	05
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-91	05
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	06
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	06
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	06
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	06
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	06
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	06
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	06
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	06
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	41	06
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	06
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	06
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	06
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-41	06
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	07
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	07
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	07
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	07
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	07
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	07
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	07

(For Use Under F P e Schedule)
(EXHIBIT "A-1" nt.)

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	07
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	41	07
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	07
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	07
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	07
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-41	07
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	08
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	08
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	08
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	08
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	08
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	08
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	08
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	08
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	41	08
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	08
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	08
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	08
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-41	08
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	09
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	09
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	09
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	09
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	09
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	09
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	09
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	09
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	141	09
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	09
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	09
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	09
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-141	09
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	10
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	10
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	10
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	10
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	10
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	10
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	10
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	10
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	191	10
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	10
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	10
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	10
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-191	10
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	11
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	11

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	11
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	11
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	11
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	11
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	11
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	11
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	191	11
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	11
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	11
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	11
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-191	11
000807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-15	12
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-9	12
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-3	12
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-17	12
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-4	12
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-2	12
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-14	12
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-12	12
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	291	12
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	14	12
020744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	35	12
020785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	27	12
070020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-291	12

Total Receipt TQ: 0 0

Total Delivery TQ: 0 0

NUMBER OF RECEIPT POINTS: 13
NUMBER OF DELIVERY POINTS: 0

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

April 4, 1995

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 1 to
Gas Transportation Agreement
Dated September 1, 1993
Service Package No. 2448

Dear George:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, agree to amend the Agreement effective January 1, 1994 through (term. date) to allow TENNESSEE GAS MARKETING CO. to act as agent for DELTA NAT GAS, in accordance with section 14.3 of Article III in the General Terms and conditions of Tennessee's effective FERC Gas Tariff, for the capacity listed in Exhibit A-1. The remaining Primary Capacity for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-3720.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

G P Gallans

Greg Gallans, Account Manager

ACCEPTED AND AGREED TO
This 6th Day of April, 1995

TENNESSEE GAS PIPELINE COMPANY

By: [signature]

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 31ST Day of OCTOBER, 1994

DELTA NATURAL GAS COMPANY INC

By: Alan C. Heath

Title: V.P. OPNS. & ENG.

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

EXHIBIT "A"
TO GAS TRANSPORTATION AGREEMENT
DATED September 1st, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ICE PACKAGE: 2448

DMENT EFFECTIVE DATE: September 1st, 1993

Monthly MDQ January	1,500	Monthly MDQ May	600	Monthly MDQ September	400
Monthly MDQ February	1,500	Monthly MDQ June	400	Monthly MDQ October	600
Monthly MDQ March	1,000	Monthly MDQ July	372	Monthly MDQ November	1,000
Monthly MDQ April	800	Monthly MDQ August	372	Monthly MDQ December	1,500

ER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	MONTHLY QTY	METER-TQ
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL01	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL02	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL03	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL04	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL05	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL06	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL07	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL08	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL09	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL10	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL11	52
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	999	DQL12	52
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL01	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL02	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL03	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL04	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL05	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL06	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL07	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL08	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL09	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL10	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL11	35
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL12	35
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL01	1
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL02	1
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL03	1
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL04	1
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL05	1
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL06	1

(For Use Under G P 'e Schedule)
(EXHIBIT "A" t.)

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	03
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	03
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	03
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	03
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	03
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	03
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	03
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	709	03
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	03
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	03
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	03
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	628	0	03
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	04
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	04
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	04
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	04
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	04
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	04
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	04
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	04
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	04
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	04
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	509	04
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	04
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	04
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	04
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	428	0	04
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	05
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	05
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	05
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	05
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	05
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	05
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	05
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	05
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	05
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	05
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	309	05
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	05
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	05
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	05
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	228	0	05
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	06
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	06
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	06
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	06
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	06

GAS TRANSPOR TION AGREEMENT
(For Use Under G J Schedule)
(EXHIBIT "A" t.)

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	06
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	06
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	06
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	06
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	06
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	109	06
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	06
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	06
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	06
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	28	0	06
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	07
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	07
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	07
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	07
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	07
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	07
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	07
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	07
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	07
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	07
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	81	07
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	07
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	07
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	08
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	08
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	08
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	08
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	08
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	08
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	08
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	08
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	08
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	08
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	81	08
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	08
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	08
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	08
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	09
01347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	09
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	09
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	09
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	09
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	09
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	09
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	09
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	09

(For Use Under [illegible] G Rate Schedule)
(EXHIBIT [illegible])

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	09
741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	109	09
743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	09
744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	09
785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	09
020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	28	0	09
807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	10
347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	10
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	10
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	10
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	10
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	10
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	10
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	10
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	10
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	10
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	309	10
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	10
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	10
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	10
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	228	0	10
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	11
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	11
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	11
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	11
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	11
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	11
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	11
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	11
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	11
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	11
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	709	11
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	11
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	11
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	11
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	628	0	11
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	12
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	12
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	12
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	12
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	12
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	12
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	12
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	12
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	12
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	12
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	1,209	12

(For Use Under FT-G te Schedule)

EXHIBIT "A-1"
SHOWING REQUESTED CHANGES
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

LTA NATURAL GAS COMPANY INC
FECTIVE DATE OF AMENDMENT: January 1, 1994
TE SCHEDULE: FT-G
RVICE PACKAGE: 2448

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	01
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	01
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	01
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	01
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	01
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	01
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	01
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	01
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	01
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1,128	01
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	01
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	01
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	01
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1,128	01
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	02
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	02
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	02
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	02
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	02
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	02
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	02
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	02
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	02
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1,128	02
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	02
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	02
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	02
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1,128	02
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	03
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	03
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	03
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	03
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	03
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	03
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	03
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	03
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	03
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	628	03

GAS TRANSPORTA ON AGREEMENT
(For Use Under F. Rat Schedule)
(EXHIBIT "A-1" c ..)

ER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	03
744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	03
785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	03
020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-628	03
807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	04
215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	04
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	04
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	04
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	04
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	04
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	04
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	04
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	04
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	428	04
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	04
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	04
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	04
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-428	04
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	05
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	05
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	05
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	05
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	05
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	05
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	05
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	05
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	05
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	228	05
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	05
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	05
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	05
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-228	05
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	06
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	06
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	06
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	06
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	06
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	06
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	06
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	06
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	06
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	28	06
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	06
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	06
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	06
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-28	06
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	07

(For Use Under F? Ra?? Schedule)
(EXHIBIT "A ..." c.)

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	07
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	07
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	07
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	07
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	07
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	07
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	07
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	07
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	07
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	07
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	08
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	08
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	08
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	08
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	08
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	08
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	08
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	08
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	08
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	08
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	08
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	08
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	09
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	09
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	09
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	09
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	09
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	09
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	09
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	09
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	09
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	28	09
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	09
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	09
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	09
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-28	09
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	10
010215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	10
011057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	10
011119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	10
011127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	10
011624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	10
011971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	10
012013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	10
012020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	10
020741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	228	10
020743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	10

(For Use Under F' R Schedule)
(EXHIBIT "A 1" .t.)

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	10
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	10
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-228	10
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	11
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	11
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	11
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	11
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	11
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	11
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	11
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	11
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	11
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	628	11
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	11
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	11
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	11
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-628	11
00807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	0	-52	12
10215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	0	-1	12
11057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-27	12
11119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	0	-13	12
11127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	0	-62	12
11624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-42	12
11971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	0	-8	12
12013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	0	-9	12
12020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	0	-42	12
20741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	0	1,128	12
20743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	12
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	12
20785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	12
70020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	0	-1,128	12

Total Receipt TQ: 0 0

Total Delivery TQ: 0 0

NUMBER OF RECEIPT POINTS: 14
NUMBER OF DELIVERY POINTS: 0

Service Package 9069
Amendment No. 0

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

THIS AGREEMENT is made and entered into as of the 19th day of December, 1994, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware Corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY INC, a KENTUCKY Corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

ARTICLE I

DEFINITIONS

1.1 TRANSPORTATION QUANTITY (TQ) - shall mean the maximum daily quantity (MDQ) of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each month of each year during the term hereof. Shipper shall elect a Transportation Quantity (TQ) for each month of the year and specify the delivery point meters to which service under this Rate Schedule applies. Any limitations of the quantities to be delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II

TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-G, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III

POINT(S) OF RECEIPT AND DELIVERY

The Primary Receipt and Delivery Points shall be those points specified on Exhibit "A" attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V

QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the Parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter or a downstream pipeline, then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI

RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the effective date hereof, the rates, charges and surcharges to be paid by Shipper to Transporter for the transportation service provided herein, including compensation for system fuel and losses, shall be in accordance with Transporter's Rate Schedule FT-G and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-G (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE VII

BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII

GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-G and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX

REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All Parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no Party shall be liable to any other Party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Subpart B, Part 284 of the FERC Regulations.

ARTICLE X

RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified, the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI

WARRANTIES

11.1 In addition to the warranties set forth in Article IX of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit "A" attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII

TERM

12.1 This Agreement shall be effective as of the 19th day of December, 1994, and shall remain in force and effect until 31st day of December, 1995 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the Primary Term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice as described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1 shall survive the other parts of this Agreement until such time as such balancing has been accomplished; provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

12.3 This Agreement will terminate automatically upon written notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII

NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER: TENNESSEE GAS PIPELINE COMPANY
P. O. Box 2511
Houston, Texas 77252-2511
Attention: Transportation Marketing

SHIPPER:

NOTICES: DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797
Attention: GEORGE S. BILLINGS

BILLING: DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797
Attention: BRIAN S. RAMSEY

or to such other address as either Party shall designate by formal written notice to the other.

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

ARTICLE XIV

ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV

MISCELLANEOUS

15.1 The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either Party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this Agreement shall be or become effective, until Shipper has submitted a request for change through the TENN-SPEED® 2 System and Shipper has been notified through TENN-SPEED 2 of Transporter's agreement to such change.

15.4 Exhibit "A" attached hereto is incorporated herein by reference and made a part hereof for all purposes.

Service Package 9069
Amendment No. 0

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

BY: ______________________
Director, Transportation Services
Central Region

DELTA NATURAL GAS COMPANY INC.

BY: ______________________

TITLE: Mgr. - Gas Supply

DATE: 2-20-95

GAS TRANSPOR' ION AGREEMENT
(For Use Under ı G :e Schedule)

EXHIBIT "A"
AMENDMENT #0 TO GAS TRANSPORTATION AGREEMENT
DATED December 19, 1994
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ELTA NATURAL GAS COMPANY INC
FFECTIVE DATE OF AMENDMENT: December 19, 1994
ATE SCHEDULE: FT-G
ERVICE PACKAGE: 9069

ONTHLY MDQS:								
	(01) January	250	(04) April	75	(07) July	50	(10) October	100
	(02) February	250	(05) May	50	(08) August	50	(11) November	175
	(03) March	150	(06) June	50	(09) September	100	(12) December	250

ETER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	250	250	01
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	250	250	02
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	150	150	03
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	75	75	04
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	50	50	05
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	50	50	06
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	50	50	07
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	50	50	08
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	100	100	09
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	100	100	10
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	175	175	11
20744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	250	250	12
				Total Receipt TQ:				1,550	1,550	
20813	WEST BEND SALES		POWELL	KY	02	D	087	250	250	01
20813	WEST BEND SALES		POWELL	KY	02	D	087	250	250	02
20813	WEST BEND SALES		POWELL	KY	02	D	087	150	150	03
20813	WEST BEND SALES		POWELL	KY	02	D	087	75	75	04
20813	WEST BEND SALES		POWELL	KY	02	D	087	50	50	05

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
0813	WEST BEND SALES		POWELL	KY	02	D	087	50	50	06
0813	WEST BEND SALES		POWELL	KY	02	D	087	50	50	07
0813	WEST BEND SALES		POWELL	KY	02	D	087	50	50	08
0813	WEST BEND SALES		POWELL	KY	02	D	087	100	100	09
0813	WEST BEND SALES		POWELL	KY	02	D	087	100	100	10
0813	WEST BEND SALES		POWELL	KY	02	D	087	175	175	11
0813	WEST BEND SALES		POWELL	KY	02	D	087	250	250	12
				Total Delivery TQ:				1,550	1,550	

MBER OF RECEIPT POINTS AFFECTED: 1
MBER OF DELIVERY POINTS AFFECTED: 1

ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

Exhibit 1-17

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

October 25, 1993

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

Re: Gas Transportation Agreement
TGP Contract No. T-2448

Dear Mr. Billings:

Enclosed for retention by Delta Natural Gas Company, Inc. is a fully executed original of the Gas Transportation Agreement for the referenced request.

I have enjoyed working with you on your transportation request and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE COMPANY

Greg

Greg Jallans
Sr. Account Executive

Enclosure

cc: Files

Contract No.: 2448

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1st day of September, 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

W I T N E S S E T H:

That in consideration of the premises and of the mutual covenants and agreements herein contained, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity (MDQ) of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each month of each year during the term hereof. Shipper shall elect an MDQ for each month of the year and specify the delivery point meters to which service under this Rate Schedule applies. Any limitations of the quantities to be delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II
TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-G, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III
POINT(S) OF RECEIPT AND DELIVERY

The Primary Receipt and Delivery Points shall be those points specified on Exhibit A attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V
QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI
RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the date of execution, the rates, charges and surcharges to be paid by Shipper to Transporter for the transportation service provided herein, including compensation for system fuel and losses, shall be in accordance with Transporter's Rate Schedule FT-G and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-G (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter's just and reasonable rates.

ARTICLE VII
BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII
GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-G and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX
REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no party shall be liable to any other party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Part 284, Subpart G of the FERC Regulations.

ARTICLE X
RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI
WARRANTIES

11.1 In addition to the warranties set forth in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit A attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty, express or implied, by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII
TERM

12.1 This Agreement shall be effective as of September 1, 1993, and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless shipper provides notice as described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1, shall survive the other parts of this Agreement until such time as such balancing has been accomplished;

12.3 This Agreement will terminate upon notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII
NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the party intended to receive the same, as follows:

provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

TRANSPORTER: Tennessee Gas Pipeline Company
P. O. Box 2511
Houston, Texas 77252-2511

Attention: Transportation Marketing

SHIPPER:

NOTICES: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

BILLING: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE XIV
ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

GAS TRANSPORT TION AGREEMENT
(For Use Under G R e Schedule)

EXHIBIT "A"
AMENDMENT #1 TO GAS TRANSPORTATION AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

LTA NATURAL GAS COMPANY INC
FECTIVE DATE OF AMENDMENT: January 1, 1994
TE SCHEDULE: FT-G
RVICE PACKAGE: 2448

NTHLY MDQS:								
(01) January	1,500	(04) April	800	(07) July	372	(10) October	600
(02) February	1,500	(05) May	600	(08) August	372	(11) November	1,000
(03) March	1,000	(06) June	400	(09) September	400	(12) December	1,500

TER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ	BILLABLE-TQ	MONTH
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	01
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	01
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	01
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	01
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	01
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	01
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	01
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	01
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	01
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	01
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	1,209	01
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	01
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	01
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	01
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1,128	0	01
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	02
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	02
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	02
1057	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	27	0	02
1119	CHEVRON-S MARSH IS BLK 61 C	LOUISIANA LAND AND EXPLORATION	OFFSHORE-FEDERA	OL	01	R	500	13	0	02
1127	TEXACO-EUGENE ISLAND BLK 338 A	TEXACO EXPLORATION AND PRODUCT	OFFSHORE-FEDERA	OL	01	R	500	62	0	02
1624	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	42	0	02
1971	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	8	0	02
2013	CIG/TGP - SABINE RIVER TRANSPO	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	01	R	800	9	0	02
2020	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	42	0	02
0741	STA 47 POOLING POINT		OUACHITA	LA	01	R	100	81	1,209	02
0743	STA 834 POOLING POINT		FRANKLIN	LA	01	R	800	0	10	02
0744	STA 542 POOLING POINT		NOXUBEE	MS	01	R	500	0	152	02
0785	STATION 32 POOLING POINT		JASPER	TX	00	R	100	0	94	02
0020	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	1,128	0	02
0807	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	52	0	03
1347	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	35	35	03
0215	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	1	0	03

ARTICLE XV
MISCELLANEOUS

15.1 The interpretation and performance of this contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this agreement shall be or become effective, except by the execution of by both Parties of a written amendment.

15.4 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

~~BY:~~ [signature] JB

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

DELTA NATURAL GAS COMPANY, INC.

BY: George S. Billings
George S. Billings

TITLE: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2448

5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL07	1
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL08	1
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL09	1
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL10	1
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL11	1
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL12	1
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	27
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	27
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	13
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	13
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	13
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	13
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	13
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	13
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	13
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL01	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL02	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL03	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL04	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL05	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL06	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL07	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL08	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL09	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL10	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL11	62
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL12	62
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	42

SERVICE PACKAGE NO. 2448
AMENDMENT NO. 0

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

R	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	42
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	42
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	8
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	8
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL01	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL02	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL03	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL04	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL05	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL06	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL07	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL08	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL09	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL10	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL11	9
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL12	9
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL01	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL02	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL03	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL04	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL05	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL06	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL07	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL08	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL09	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL10	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL11	42
20	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL12	42
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL01	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL02	81

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

R	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL03	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL04	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL05	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL06	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL07	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL08	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL09	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL10	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL11	81
41	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL12	81
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL01	1,128
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL02	1,128
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL03	628
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL04	428
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL05	228
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL06	28
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL07	0
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL08	0
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL09	28
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL10	228
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL11	628
020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL12	1,128
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL01	190
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL02	190
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL03	127
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL04	100
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL05	75
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL06	50
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL07	55
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL08	55
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL09	60
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL10	75
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL11	127
212	0	DELTA-SALT LICK KY	DELTA NATURAL GAS COMPANY INC	BATH	KY	02	D	087	DQL12	190
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL01	1,260
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL02	1,260
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL03	840
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL04	675
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL05	505
462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL06	330

SERVICE PACKAGE NO. 2448
AMENDMENT NO. 0

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

ΓER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL07	297
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL08	297
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL09	320
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL10	500
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL11	840
0462	0	DELTA-FARMERS KY	DELTA NATURAL GAS COMPANY INC	ROWAN	KY	02	D	087	DQL12	1,260
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL01	50
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL02	50
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL03	33
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL04	25
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL05	20
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL06	20
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL07	20
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL08	20
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL09	20
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL10	25
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL11	33
0733	0	DELTA - KINDER/HILDA SALES		ROWAN	KY	02	D	087	DQL12	50

NUMBER OF RECEIPT POINTS: 12
NUMBER OF DELIVERY POINTS: 3

Exhibit 1-18

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

October 25, 1993

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

Re: Gas Transportation Agreement
TGP Contract No. T-2515

Dear Mr. Billings:

Enclosed for retention by Delta Natural Gas Company, Inc. is a fully executed original of the Gas Transportation Agreement for the referenced request.

I have enjoyed working with you on your transportation request and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE COMPANY

Greg

Greg Jallans
Sr. Account Executive

Enclosure

cc: Files

Contract No.: 2515

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1st day of September, 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

W I T N E S S E T H:

That in consideration of the premises and of the mutual covenants and agreements herein contained, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity (MDQ) of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each month of each year during the term hereof. Shipper shall elect an MDQ for each month of the year and specify the delivery point meters to which service under this Rate Schedule applies. Any limitations of the quantities to be delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II
TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-G, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III
POINT(S) OF RECEIPT AND DELIVERY

The Primary Receipt and Delivery Points shall be those points specified on Exhibit A attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V
QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI
RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the date of execution, the rates, charges and surcharges to be paid by Shipper to Transporter for the transportation service provided herein, including compensation for system fuel and losses, shall be in accordance with Transporter's Rate Schedule FT-G and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-G (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter's just and reasonable rates.

ARTICLE VII
BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII
GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-G and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX
REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no party shall be liable to any other party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Part 284, Subpart G of the FERC Regulations.

ARTICLE X
RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI
WARRANTIES

11.1 In addition to the warranties set forth in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit A attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty, express or implied, by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII
TERM

12.1 This Agreement shall be effective as of September 1, 1993, and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless shipper provides notice as described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1, shall survive the other parts of this Agreement until such time as such balancing has been accomplished;

12.3 This Agreement will terminate upon notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII
NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the party intended to receive the same, as follows:

provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

TRANSPORTER: Tennessee Gas Pipeline Company
P. O. Box 2511
Houston, Texas 77252-2511

Attention: Transportation Marketing

SHIPPER:

NOTICES: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

BILLING: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE XIV
ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV
MISCELLANEOUS

15.1 The interpretation and performance of this contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this agreement shall be or become effective, except by the execution of by both Parties of a written amendment.

15.4 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

BY: ________________________
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

BY: ________________________
George S. Billings

TITLE: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2515

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

EXHIBIT "A"
TO GAS TRANSPORTATION AGREEMENT
DATED September 1st, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

:E PACKAGE: 2515

1ENT EFFECTIVE DATE: September 1st, 1993

Monthly MDQ January	5,500	Monthly MDQ May	2,500	Monthly MDQ September	1,676
Monthly MDQ February	5,500	Monthly MDQ June	1,676	Monthly MDQ October	2,500
Monthly MDQ March	4,000	Monthly MDQ July	1,676	Monthly MDQ November	3,800
Monthly MDQ April	3,000	Monthly MDQ August	1,676	Monthly MDQ December	5,500

	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	MONTHLY QTY	METER-TQ
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL01	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL02	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL03	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL04	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL05	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL06	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL07	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL08	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL09	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL10	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL11	235
7	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL12	235
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL01	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL02	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL03	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL04	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL05	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL06	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL07	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL08	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL09	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL10	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL11	161
7	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL12	161
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL01	3
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL02	3
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL03	3
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL04	3
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL05	3
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL06	3

5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL07	3
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL08	3
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL09	3
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL10	3
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL11	3
5	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL12	3
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	136
7	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	136
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	40
9	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	40
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	40
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	40
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	40
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	40
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL01	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL02	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL03	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL04	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL05	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL06	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL07	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL08	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL09	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL10	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL11	265
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL12	265
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	56
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	56

SERVICE PACKAGE NO. 2515
AMENDMENT NO. 0

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
4	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	56
4	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	56
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	35
1	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	35
3	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL01	216
3	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL02	216
3	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL03	216
3	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL04	216020208 0 DELTA-BEREA KY
A NATURAL GAS COMPANY INC MADISON					KY	02	D	087	DQL01	5,500
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL02	5,500
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL03	4,000
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL04	3,000
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL05	2,500
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL06	1,676
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL07	1,676
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL08	1,676
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL09	1,676
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL10	2,500
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL11	3,800
8	0	DELTA-BEREA KY	DELTA NATURAL GAS COMPANY INC	MADISON	KY	02	D	087	DQL12	5,500

NUMBER OF RECEIPT POINTS: 12
NUMBER OF DELIVERY POINTS: 1

Exhibit 1-19

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

October 25, 1993

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

Re: Gas Transportation Agreement
TGP Contract No. T-2555

Dear Mr. Billings:

Enclosed for retention by Delta Natural Gas Company, Inc. is a fully executed original of the Gas Transportation Agreement for the referenced request.

I have enjoyed working with you on your transportation request and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE COMPANY

Greg Jallans
Sr. Account Executive

Enclosure

cc: Files

Contract No.: 2555

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1st day of September, 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

W I T N E S S E T H:

That in consideration of the premises and of the mutual covenants and agreements herein contained, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity (MDQ) of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each month of each year during the term hereof. Shipper shall elect an MDQ for each month of the year and specify the delivery point meters to which service under this Rate Schedule applies. Any limitations of the quantities to be delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II
TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-G, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III
POINT(S) OF RECEIPT AND DELIVERY

The Primary Receipt and Delivery Points shall be those points specified on Exhibit A attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V
QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI
RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the date of execution, the rates, charges and surcharges to be paid by Shipper to Transporter for the transportation service provided herein, including compensation for system fuel and losses, shall be in accordance with Transporter's Rate Schedule FT-G and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-G (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter's just and reasonable rates.

ARTICLE VII
BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII
GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-G and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX
REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no party shall be liable to any other party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Part 284, Subpart G of the FERC Regulations.

ARTICLE X
RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI
WARRANTIES

11.1 In addition to the warranties set forth in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit A attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty, express or implied, by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII
TERM

12.1 This Agreement shall be effective as of September 1, 1993, and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless shipper provides notice as described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1, shall survive the other parts of this Agreement until such time as such balancing has been accomplished;

12.3 This Agreement will terminate upon notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII
NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the party intended to receive the same, as follows:

provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

TRANSPORTER: Tennessee Gas Pipeline Company
P. O. Box 2511
Houston, Texas 77252-2511

Attention: Transportation Marketing

SHIPPER:

NOTICES: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

BILLING: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE XIV
ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV
MISCELLANEOUS

15.1 The interpretation and performance of this contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this agreement shall be or become effective, except by the execution of by both Parties of a written amendment.

15.4 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

BY: ________________
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

BY: ________________
George S. Billings

TITLE: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2555

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

EXHIBIT "A"
TO GAS TRANSPORTATION AGREEMENT
DATED September 1st, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ICE PACKAGE: 2555

DMENT EFFECTIVE DATE: September 1st, 1993

Monthly MDQ January	8,561	Monthly MDQ May	2,800	Monthly MDQ September	2,000
Monthly MDQ February	8,561	Monthly MDQ June	2,000	Monthly MDQ October	3,644
Monthly MDQ March	5,600	Monthly MDQ July	2,000	Monthly MDQ November	5,000
Monthly MDQ April	4,000	Monthly MDQ August	2,000	Monthly MDQ December	8,561

ER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	MONTHLY QTY	METER-TQ
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL01	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL02	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL03	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL04	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL05	5
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL06	3
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL07	3
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL08	3
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL09	3
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL10	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL11	6
307	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL12	6
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL01	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL02	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL03	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL04	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL05	314
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL06	224
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL07	224
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL08	224
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL09	224
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL10	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL11	408
347	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL12	408
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL01	260
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL02	260
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL03	260
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL04	260
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL05	200
215	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL06	143

15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL07	143
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL08	143
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL09	143
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL10	260
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL11	260
15	0	JUPITER-GULF OF MEXICO DEHYD		CAMERON	LA	01	R	800	DQL12	260
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	71
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	50
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	50
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	50
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	50
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	92
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	92
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	468
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	334
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	334
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	334
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	334
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	609
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	609
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL01	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL02	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL03	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL04	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL05	61
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL06	44
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL07	44
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL08	44
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL09	44
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL10	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL11	80
127	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL12	80
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	128
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	128
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	128
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	128
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	98
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	70
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	70
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	70
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	70
624	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	128

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

ER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
524	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	128
524	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	128
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	604
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	431
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	431
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	431
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	431
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	786
971	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	786
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL01	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL02	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL03	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL04	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL05	317
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL06	227
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL07	227
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL08	227
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL09	227
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL10	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL11	413
013	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL12	413
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL01	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL02	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL03	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL04	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL05	392
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL06	280
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL07	280
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL08	280
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL09	280
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL10	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL11	510
2020	0	TRANSCO - FALFURRIAS TRANSPORT		JIM WELLS	TX	00	R	100	DQL12	510
0741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL01	352
0741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL02	352

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

ETER	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL03	352
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL04	352
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL05	270
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL06	193
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL07	193
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL08	193
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL09	193
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL10	352
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL11	352
20741	0	STA 47 POOLING POINT		QUACHITA	LA	01	R	100	DQL12	352
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL01	4,917
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL02	4,917
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL03	1,956
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL04	356
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL05	0
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL06	1
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL07	1
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL08	1
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL09	1
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL10	0
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL11	1,356
70020	0	TGP - PORTLAND STORAGE WITHDRA		SUMNER	TN	01	R	100	DQL12	4,917
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL01	8,561
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL02	8,561
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL03	5,600
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL04	4,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL05	2,800
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL06	2,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL07	2,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL08	2,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL09	2,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL10	3,644
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL11	5,000
20248	0	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS COMPANY INC	GARRARD	KY	02	D	087	DQL12	8,561

NUMBER OF RECEIPT POINTS: 12
NUMBER OF DELIVERY POINTS: 1

Exhibit 1-20

Tennessee Gas Pipeline
A Tenneco Company

Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511
(713) 757-2131

TENNECO

October 25, 1993

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

Re: Gas Transportation Agreement
TGP Contract No. T-2516

Dear Mr. Billings:

Enclosed for retention by Delta Natural Gas Company is a fully executed original of the Gas Transportation Agreement for the referenced request.

I have enjoyed working with you on your transportation request and look forward to working with you on any of your future transportation needs. If I may be of further assistance, please contact me at (713) 757-3720. Thank you.

Sincerely,

TENNESSEE GAS PIPELINE COMPANY

Greg

Greg Ja[illegible]ans
Sr. Account Executive

Enclosure

cc: Files

Contract No.: 2516

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

THIS AGREEMENT is made and entered into as of the 1st day of September, 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation, hereinafter referred to as "Transporter" and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Shipper." Transporter and Shipper shall collectively be referred to herein as the "Parties."

W I T N E S S E T H:

That in consideration of the premises and of the mutual covenants and agreements herein contained, Transporter and Shipper agree as follows:

ARTICLE I
DEFINITIONS

1.1 TRANSPORTATION QUANTITY - shall mean the maximum daily quantity (MDQ) of gas which Transporter agrees to receive and transport on a firm basis, subject to Article II herein, for the account of Shipper hereunder on each day during each month of each year during the term hereof. Shipper shall elect an MDQ for each month of the year and specify the delivery point meters to which service under this Rate Schedule applies. Any limitations of the quantities to be delivered to each Point of Delivery shall be as specified on Exhibit A attached hereto.

1.2 EQUIVALENT QUANTITY - shall be as defined in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE II
TRANSPORTATION

Transportation Service - Transporter agrees to accept and receive daily on a firm basis in accordance with Rate Schedule FT-G, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

ARTICLE III
POINT(S) OF RECEIPT AND DELIVERY

The Primary Receipt and Delivery Points shall be those points specified on Exhibit A attached hereto.

ARTICLE IV

All facilities are in place to render the service provided for in this Agreement.

ARTICLE V
QUALITY SPECIFICATIONS AND STANDARDS FOR MEASUREMENT

For all gas received, transported and delivered hereunder the parties agree to the Quality Specifications and Standards for Measurement as specified in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1. To the extent that no new measurement facilities are installed to provide service hereunder, measurement operations will continue in the manner in which they have previously been handled. In the event that such facilities are not operated by Transporter then responsibility for operations shall be deemed to be Shipper's.

ARTICLE VI
RATES AND CHARGES FOR GAS TRANSPORTATION

6.1 TRANSPORTATION RATES - Commencing upon the date of execution, the rates, charges and surcharges to be paid by Shipper to Transporter for the transportation service provided herein, including compensation for system fuel and losses, shall be in accordance with Transporter's Rate Schedule FT-G and the General Terms and Conditions of Transporter's FERC Gas Tariff.

6.2 INCIDENTAL CHARGES - Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

6.3 CHANGES IN RATES AND CHARGES - Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FT-G (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter's just and reasonable rates.

ARTICLE VII
BILLINGS AND PAYMENTS

Transporter shall bill and Shipper shall pay all rates and charges in accordance with Articles V and VI, respectively, of the General Terms and Conditions of Transporter's FERC Gas Tariff.

ARTICLE VIII
GENERAL TERMS AND CONDITIONS

This Agreement shall be subject to the effective provisions of Transporter's Rate Schedule FT-G and to the General Terms and Conditions incorporated therein, as the same may be changed or superseded from time to time in accordance with the rules and regulations of the FERC.

ARTICLE IX
REGULATION

9.1 This Agreement shall be subject to all applicable and lawful governmental statutes, orders, rules and regulations and is contingent upon the receipt and continuation of all necessary regulatory approvals or authorizations upon terms acceptable to Transporter. This Agreement shall be void and of no force and effect if any necessary regulatory approval is not so obtained or continued. All parties hereto shall cooperate to obtain or continue all necessary approvals or authorizations, but no party shall be liable to any other party for failure to obtain or continue such approvals or authorizations.

9.2 The transportation service described herein shall be provided subject to Part 284, Subpart G of the FERC Regulations.

ARTICLE X
RESPONSIBILITY DURING TRANSPORTATION

Except as herein specified the responsibility for gas during transportation shall be as stated in the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1.

ARTICLE XI
WARRANTIES

11.1 In addition to the warranties set forth in Article I of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper warrants the following:

(a) Shipper warrants that all upstream and downstream transportation arrangements are in place, or will be in place as of the requested effective date of service, and that it has advised the upstream and downstream transporters of the receipt and delivery points under this Agreement and any quantity limitations for each point as specified on Exhibit A attached hereto. Shipper agrees to indemnify and hold Transporter harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

(b) Shipper agrees to indemnify and hold Transporter harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses (including reasonable attorneys fees) arising from or out of breach of any warranty, express or implied, by Shipper herein.

11.2 Transporter shall not be obligated to provide or continue service hereunder in the event of any breach of warranty.

ARTICLE XII
TERM

12.1 This Agreement shall be effective as of September 1, 1993, and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Transporter to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless shipper provides notice as described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

12.2 Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Transporter's FERC Gas Tariff Volume No. 1, shall survive the other parts of this Agreement until such time as such balancing has been accomplished,

12.3 This Agreement will terminate upon notice from Transporter in the event Shipper fails to pay all of the amount of any bill for service rendered by Transporter hereunder in accord with the terms and conditions of Article VI of the General Terms and Conditions of Transporter's FERC Tariff.

ARTICLE XIII
NOTICE

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under this Agreement shall be in writing and mailed to the post office address of the party intended to receive the same, as follows:

provided, however, that Transporter notifies Shipper of such imbalance no later than twelve months after the termination of this Agreement.

Am

TRANSPORTER: Tennessee Gas Pipeline Company
P. O. Box 2511
Houston, Texas 77252-2511

Attention: Transportation Marketing

SHIPPER:

NOTICES: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: George S. Billings

BILLING: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE XIV
ASSIGNMENTS

14.1 Either Party may assign or pledge this Agreement and all rights and obligations hereunder under the provisions of any mortgage, deed of trust, indenture, or other instrument which it has executed or may execute hereafter as security for indebtedness. Otherwise, Shipper shall not assign this Agreement or any of its rights hereunder, except in accord with Article III, Section 11 of the General Terms and Conditions.

14.2 Any person which shall succeed by purchase, merger, or consolidation to the properties, substantially as an entirety, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

ARTICLE XV
MISCELLANEOUS

15.1 The interpretation and performance of this contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to the doctrines governing choice of law.

15.2 If any provisions of this Agreement is declared null and void, or voidable, by a court of competent jurisdiction, then that provision will be considered severable at either party's option; and if the severability option is exercised, the remaining provisions of the Agreement shall remain in full force and effect.

15.3 Unless otherwise expressly provided in this Agreement or Transporter's Gas Tariff, no modification of or supplement to the terms and provisions stated in this agreement shall be or become effective, except by the execution of by both Parties of a written amendment.

15.4 Exhibit A attached hereto is incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed in several counterparts as of the date first hereinabove written.

TENNESSEE GAS PIPELINE COMPANY

BY: ______________________
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

BY: George S. Billings
George S. Billings

TITLE: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2516

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

EXHIBIT "A"
TO GAS TRANSPORTATION AGREEMENT
DATED September 1st, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ICE PACKAGE: 2516

DMENT EFFECTIVE DATE: September 1st, 1993

Monthly MDQ January	400	Monthly MDQ May	200	Monthly MDQ September	250
Monthly MDQ February	400	Monthly MDQ June	150	Monthly MDQ October	300
Monthly MDQ March	300	Monthly MDQ July	150	Monthly MDQ November	300
Monthly MDQ April	200	Monthly MDQ August	150	Monthly MDQ December	400

R	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	MONTHLY QTY	METER-TQ
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL01	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL02	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL03	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL04	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL05	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL06	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL07	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL08	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL09	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL10	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL11	15
07	0	SAMEDAN-BRAZOS BLK A-52 C		OFFSHORE-FEDERA	OT	00	R	100	DQL12	15
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL01	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL02	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL03	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL04	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL05	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL06	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL07	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL08	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL09	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL10	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL11	11
47	0	CHEVRON - MUSTANG ISLAND 868		OFFSHORE-FEDERA	OT	00	R	999	DQL12	11
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	9

57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	9
57	0	CHEVRON-VERMILION BLK 250 C DE	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	9
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	3
19	0	CHEVRON-S MARSH IS BLK 61 C	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	3
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL01	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL02	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL03	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL04	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL05	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL06	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL07	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL08	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL09	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL10	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL11	17
27	0	TEXACO-EUGENE ISLAND BLK 338 A		OFFSHORE-FEDERA	OL	01	R	500	DQL12	17
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	4
24	0	CHEVRON-SHIP SHOAL BLK 168-D	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	4
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL01	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL02	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL03	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL04	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL05	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL06	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL07	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL08	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL09	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL10	2

GAS TRANSPORTATION AGREEMENT
(For Use Under FT-G Rate Schedule)

R	AMD	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL11	2
71	0	CHEVRON - SOUTH MARSH ISLAND 7	CHEVRON USA INC	OFFSHORE-FEDERA	OL	01	R	500	DQL12	2
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL01	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL02	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL03	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL04	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL05	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL06	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL07	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL08	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL09	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL10	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL11	14
13	0	TENNESSEE - SABINE RIVER TRANS	CHANNEL INDUSTRIES GAS CO	NEWTON	TX	00	R	800	DQL12	14
20	0	TRANSCO - FALFURRIAS TRANSPORT	TRANSCONTINENTAL GAS PIPE LINE	JIM WELLS	TX	00	R	100	DQL01	12
20	0	TRANSCO - FALFURRIAS TRANSPORT	TRANSCONTINENTAL GAS PIPE LINE	JIM WELLS	TX	00	R	100	DQL02	12
20	0	TRANSCO - FALFURRIAS TRANSPORT	TRANSCONTINENTAL GAS PIPE LINE	JIM WELLS	TX	00	R	100	DQL03	12
20	0	TRANSCO - FALFURRIAS TRANSPORT	TRANSCONTINENTAL GAS PIPE LINE	JIM WELLS	TX	00	R	100	DQL04	12020430 0 DELTA-JEFFERSONVILLE KY
TA NATURAL GAS COMPANY INC MONTGOMERY KY 02 D 087 DQL01 400										
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL02	400
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL03	300
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL04	200
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL05	200
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL06	150
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL07	150
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL08	150
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL09	250
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL10	300
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL11	300
30	0	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS COMPANY INC	MONTGOMERY	KY	02	D	087	DQL12	400

NUMBER OF RECEIPT POINTS: 11
NUMBER OF DELIVERY POINTS: 1

Exhibit 1-21

Tennessee Gas Pipeline
Tenneco Energy
1010 Milam Street
PO Box 2511
Houston, Texas 77252 2511

Tel 713 757 2131

JUL - 1 1996
RECEIVED

TENNECO
Energy

June 26, 1996

Mr. George S. Billings
Delta Natural Gas Company Inc.
3617 Lexington Road
Winchester, KY 40391-9797

Re: Amendment No. 1 and 2 to
Gas Storage Service Agreement
Dated September 1, 1993
Service Package No. 2366

Dear Mr. Billings:

Enclosed for retention is a fully executed original of the Amendment No. 1 and 2 to Gas Storage Service Agreement for Service Package No. 2366 dated September 1, 1993 referenced above.

If you have any questions, please do not hesitate to contact me at (713) 757-4010.

Sincerely,

Carol Wehlmann

Carol Wehlmann
Central Accounts

CW/so

Enclosure

Tennessee Gas Pipeline
Tenneco Energy
1010 Milam Street
PO Box 2511
Houston, Texas 77252 2511

Tel 713 757 2131

TENNECO
Energy

May 23, 1996

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 1 to
Gas Storage Service Agreement
Dated September 1, 1993
Service Package No. 2366

Dear MR. BILLINGS:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, (DELTA NAT GAS) agree to amend the Agreement effective November 1, 1995, through October 31st, 1996, to assign capacity, through Tennessee's capacity release mechanism, to TENNESSEE GAS MARKETING CO. The remaining Maximum Storage Quantity and Injection/Deliverability rights for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-4010.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

Carol Wehlmann

CAROL WEHLMANN
CENTRAL ACCOUNTS

DELTA NATURAL GAS COMPANY INC
May 23, 1996
Page 2
Contract number: 2366
Amendment number: 1
Amendment effective date: November 1, 1995

ACCEPTED AND AGREED TO
This 25th Day of June, 1996

TENNESSEE GAS PIPELINE COMPANY

By: [signature]

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 11th Day of June, 1996

DELTA NATURAL GAS COMPANY INC

By: [signature]

Title: MGR. - GAS Supply

GAS STORAGE SERVICE AG. .MENT

EXHIBIT "A"
AMENDMENT #1 TO GAS STORAGE SERVICE AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

:LTA NATURAL GAS COMPANY INC
FECTIVE DATE OF AMENDMENT: November 1, 1995
.TE SCHEDULE: FS
RVICE PACKAGE: 2366
RVICE PACKAGE MSQ: 173,399
JECTION QUANTITY: 1,155
THDRAWAL QUANTITY: 1,233
RVICE POINT: Compressor Station 087 - PORTLAND Storage

TER	METER NAME	COUNTY	ST	ZONE	I/W	LEG	BILLABLE-TQ	TOTAL-TQ	ASSIGNED-TQ
0020	TGP - PORTLAND STORAGE INJECTION	SUMNER	TN	01	I	100	1,155	0	1,155
			Total Injection TQ:				1,155	0	1,155
'0020	TGP - PORTLAND STORAGE WITHDRAWAL	SUMNER	TN	01	W	100	1,233	1,233	0
			Total Withdrawal TQ:				1,233	1,233	0

IMBER OF INJECTION POINTS: 2
IMBER OF WITHDRAWAL POINTS: 1

ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

Tennessee Gas Pipeline
Tenneco Energy
1010 Milam Street
PO Box 2511
Houston, Texas 77252 2511

Tel 713 757 2131

JUN - 3 1996

RECEIVED

TENNECO
Energy

May 23, 1996

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 2 to
Gas Storage Service Agreement
Dated September 1, 1993
Service Package No. 2366

Dear MR. BILLINGS:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, (DELTA NAT GAS) agree to amend the Agreement effective November 1, 1995, through October 31st, 1996, to assign capacity, through Tennessee's capacity release mechanism, to TENNESSEE GAS MARKETING CO. The remaining Maximum Storage Quantity and Injection/Deliverability rights for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-4010.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

Carol Wehlmann
CAROL WEHLMANN
CENTRAL ACCOUNTS

DELTA NATURAL GAS COMPANY INC
May 23, 1996
Page 2
Contract number: 2366
Amendment number: 2
Amendment effective date: November 1, 1995

ACCEPTED AND AGREED TO
This 25th Day of June, 1996

TENNESSEE GAS PIPELINE COMPANY

By: _______________

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 11th Day of JUNE, 1996

DELTA NATURAL GAS COMPANY INC

By: _______________

Title: MGR. - GAS Supply

GAS STORAGE SERVICE AG. ⌐MENT

EXHIBIT "A"
AMENDMENT #2 TO GAS STORAGE SERVICE AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ELTA NATURAL GAS COMPANY INC
FFECTIVE DATE OF AMENDMENT: November 1, 1995
ATE SCHEDULE: FS
ERVICE PACKAGE: 2366
ERVICE PACKAGE MSQ: 173,399
NJECTION QUANTITY: 1,155
ITHDRAWAL QUANTITY: 1,233
ERVICE POINT: Compressor Station 087 - PORTLAND Storage

ETER	METER NAME	COUNTY	ST	ZONE	I/W	LEG	BILLABLE-TQ	TOTAL-TQ	ASSIGNED-TQ
60020	TGP - PORTLAND STORAGE INJECTION	SUMNER	TN	01	I	100	1,155	0	1,155
			Total Injection TQ:				1,155	0	1,155
70020	TGP - PORTLAND STORAGE WITHDRAWAL	SUMNER	TN	01	W	100	1,233	0	1,233
			Total Withdrawal TQ:				1,233	0	1,233

JMBER OF INJECTION POINTS: 2
JMBER OF WITHDRAWAL POINTS: 1

'ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

Tennessee Gas Pipeline
Tenneco Energy
1010 Milam Street
PO Box 2511
Houston, Texas 77252 2511

Tel 713 757 2131

JUN - 3 1996

RECEIVED

TENNECO
Energy

May 23, 1996

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 2 to
Gas Storage Service Agreement
Dated September 1, 1993
Service Package No. 2366

Dear MR. BILLINGS:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, (DELTA NAT GAS) agree to amend the Agreement effective November 1, 1995, through October 31st, 1996, to assign capacity, through Tennessee's capacity release mechanism, to TENNESSEE GAS MARKETING CO. The remaining Maximum Storage Quantity and Injection/Deliverability rights for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-4010.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

Carol Wehlmann
CAROL WEHLMANN
CENTRAL ACCOUNTS

DELTA NATURAL GAS COMPANY INC
May 23, 1996
Page 2
Contract number: 2366
Amendment number: 2
Amendment effective date: November 1, 1995

ACCEPTED AND AGREED TO
This ___ Day of __________, 19__

TENNESSEE GAS PIPELINE COMPANY

By: ______________________________

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 11th Day of June, 1996

DELTA NATURAL GAS COMPANY INC

By: [signature]

Title: MGR. - GAS Supply

GAS STORAGE SERVICE AGREEMENT

EXHIBIT "A"
AMENDMENT #2 TO GAS STORAGE SERVICE AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

DELTA NATURAL GAS COMPANY INC
EFFECTIVE DATE OF AMENDMENT: November 1, 1995
RATE SCHEDULE: FS
SERVICE PACKAGE: 2366
SERVICE PACKAGE MSQ: 173,399
INJECTION QUANTITY: 1,155
WITHDRAWAL QUANTITY: 1,233
SERVICE POINT: Compressor Station 087 - PORTLAND Storage

METER	METER NAME	COUNTY	ST	ZONE	I/W	LEG	BILLABLE-TQ	TOTAL-TQ	ASSIGNED-TQ
060020	TGP - PORTLAND STORAGE INJECTION	SUMNER	TN	01	I	100	1,155	0	1,155
			Total Injection TQ:				1,155	0	1,155
70020	TGP - PORTLAND STORAGE WITHDRAWAL	SUMNER	TN	01	W	100	1,233	0	1,233
			Total Withdrawal TQ:				1,233	0	1,233

NUMBER OF INJECTION POINTS: 2
NUMBER OF WITHDRAWAL POINTS: 1

Note: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

Tennessee Gas Pipeline
Tenneco Energy
1010 Milam Street
PO Box 2511
Houston, Texas 77252 2511

Tel 713 757 2131

TENNECO Energy

May 23, 1996

GEORGE S. BILLINGS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER, KY 40391-9797

RE: Amendment No. 1 to
Gas Storage Service Agreement
Dated September 1, 1993
Service Package No. 2366

Dear MR. BILLINGS:

TENNESSEE GAS PIPELINE COMPANY and DELTA NATURAL GAS COMPANY INC, (DELTA NAT GAS) agree to amend the Agreement effective November 1, 1995, through October 31st, 1996, to assign capacity, through Tennessee's capacity release mechanism, to TENNESSEE GAS MARKETING CO. The remaining Maximum Storage Quantity and Injection/Deliverability rights for the Agreement remains as reflected in the Attached Revised Exhibit A, barring any temporary recalls at which time the capacity released under this Amendment reverts back to DELTA NAT GAS.

Except as amended herein, all terms and provisions of the Agreement shall remain in full force and effect as written.

If the foregoing is in accordance with your understanding of the Agreement, please so indicate by signing and returning to my attention both originals of this letter. Upon Tennessee's execution, an original will be forwarded to you for your files.

Should you have any questions, please do not hesitate to contact me at (713)757-4010.

Best regards,

TENNESSEE GAS PIPELINE COMPANY

Carol Wehlmann

CAROL WEHLMANN
CENTRAL ACCOUNTS

DELTA NATURAL GAS COMPANY INC
May 23, 1996
Page 2
Contract number: 2366
Amendment number: 1
Amendment effective date: November 1, 1995

ACCEPTED AND AGREED TO
This ___ Day of __________, 19__

TENNESSEE GAS PIPELINE COMPANY

By: ______________________________

Title: Agent and Attorney in Fact

ACCEPTED AND AGREED TO
This 11th Day of June, 1996

DELTA NATURAL GAS COMPANY INC

By: Gary S. Billings

Title: MGR. - GAS Supply

GAS STORAGE SERVICE AGREEMENT

EXHIBIT "A"
AMENDMENT #1 TO GAS STORAGE SERVICE AGREEMENT
DATED September 1, 1993
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY INC

ELTA NATURAL GAS COMPANY INC
FFECTIVE DATE OF AMENDMENT: November 1, 1995
ATE SCHEDULE: FS
ERVICE PACKAGE: 2366
ERVICE PACKAGE MSQ: 173,399
NJECTION QUANTITY: 1,155
ITHDRAWAL QUANTITY: 1,233
ERVICE POINT: Compressor Station 087 - PORTLAND Storage

ETER	METER NAME	COUNTY	ST	ZONE	I/W	LEG	BILLABLE-TQ	TOTAL-TQ	ASSIGNED-TQ
50020	TGP - PORTLAND STORAGE INJECTION	SUMNER	TN	01	I	100	1,155	0	1,155
			Total Injection TQ:				1,155	0	1,155
70020	TGP - PORTLAND STORAGE WITHDRAWAL	SUMNER	TN	01	W	100	1,233	1,233	0
			Total Withdrawal TQ:				1,233	1,233	0

IMBER OF INJECTION POINTS: 2
IMBER OF WITHDRAWAL POINTS: 1

ote: Exhibit "A" is a reflection of the contract and all amendments as of the amendment effective date.

Exhibit 1-22

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
TELEPHONE 606-744-6171
FAX 606-744-3623

August 24, 1993

VIA FEDERAL EXPRESS

Mr. Gregory P. Jallans, Sr. Account Executive
Tennessee Gas Pipeline
Tenneco Building
P. O. Box 2511
Houston, Texas 77252-2511

Dear Greg:

Enclosed are duplicate originals of the following contracts:

TGP FS Market Area Contract No. 2362
TGP FS Market Area Contract No. 2363
TGP FS Market Area Contract No. 2364
TGP FS Production Area Contract No. 2365
TGP FS Production Area Contract No. 2366

These agreements have been executed by Delta Natural Gas Company, Inc. Please be advised, however, that we are not in agreement with the storage volumes allocation of the FS agreements. We believe that Delta's firm storage volumes should be allocated between market area storage and production area storage as set forth in Tennessee's March 29, 1993 compliance filing.

Our legal counsel has discussed this matter with Patrick Johnson of Tennessee's Legal Department, who indicated that Tennessee would examine storage allocations. I have also telefaxed a letter to Taylor Sherwood expressing my concern over the current allocation. Our agreement to these contracts is based upon the understanding that if Delta and Tennessee reach agreement on revision of Delta's storage allocation, such revisions will be made effective retroactively to September 1, 1993, or the date of Tennessee's implementation should that date be different.

Upon execution by Tennessee, please return one fully executed original of each agreement to my attention.

Sincerely,

George S. Billings

George S. Billings
Manager - Gas Supply

Enclosures

Tenneco Gas

1010 Milam Street
P.O. Box 2511
Houston, Texas 77252 - 2511
(713) 757-2131

TENNECO

October 29, 1993

NOV 8 1993

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391

Attn: Transportation Marketing

RE: Gas Storage Contracts
2362, 2363, 2364,
2365, 2366

Gentlemen:

Enclosed for retention are fully executed originals of the gas storage contracts between Tennessee Gas Pipeline Company and Delta Natural Gas Company, Inc.

We appreciate your willingness to transport your gas on Tennessee Gas Pipeline, and hope to maximize your opportunities.

If any questions or further assistance on transportation needs are required, please give me a call at (713) 757-3720.

Sincerely,

TENNESSEE GAS PIPELINE

Greg Jallans

Greg P. Jallans
Sr. Account Executive

Enclosures

Contract No.: 2362

GAS STORAGE CONTRACT
(For Use Under Rate Schedule FS)

THIS Contract is made as of the 1st day of September 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation herein called "Transporter," and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, herein called "Shipper." Transporter and Shipper collectively shall be referred to herein as the "Parties."

ARTICLE I - SCOPE OF CONTRACT

Following the commencement of service hereunder, in accordance with the terms of Transporter's Rate Schedule FS (Market Area), and of this Agreement, Transporter shall receive for injection for Shipper's account a daily quantity of gas up to Shipper's Maximum Injection Quantity (on any day) and Maximum Storage Quantity of 45,300 Dth (on a cumulative basis) and on demand shall withdraw from Shipper's storage account and deliver to Shipper a daily quantity of gas up to Shipper's Maximum Daily Withdrawal Quantity of 1,128 Dth.

ARTICLE II - SERVICE POINT

The point or points at which the gas is to be tendered for delivery by Transporter to Shipper under this contract shall be at the storage service point at Transporter's Compressor Station 87.

ARTICLE III - PRICE

1. Shipper agrees to pay Transporter for all natural gas storage service furnished to Shipper hereunder, including compensation for system fuel and losses, at Transporter's legally effective rate or at any effective superseding rate applicable to the type of service specified herein. Transporter's present legally effective rate for said service is contained in Transporter's Rate Schedule FS as filed with the Federal Energy Regulatory Commission.

2. Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

3. Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FS, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE IV - INCORPORATION OF RATE SCHEDULE AND TARIFF PROVISIONS

This Agreement shall be subject to the terms of Transporter's Rate Schedule FS, as filed with the Federal Energy Regulatory Commission, together with the General Terms and Conditions applicable thereto (including any changes in said Rate Schedule or General Terms and Conditions as may from time to time be filed and made effective by Transporter).

ARTICLE V - TERM OF CONTRACT

This Agreement shall be effective as of September 1, 1993 and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Tennessee to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

ARTICLE VI - NOTICES

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under the Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER:	Tennessee Gas Pipeline Company P.O. Box 2511 Houston, TX 77252-2511 Attention: Transportation Marketing
SHIPPER:	
NOTICES:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: George S. Billings
BILLING:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE VII - ASSIGNMENT

Any company which shall succeed by purchase, merger or consolidation to the properties, substantially as an entirety, of Transporter or of Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this contract. Otherwise no assignment of the contract or any of the rights or obligations thereunder shall be made by Shipper, except pursuant to the General Terms and Conditions of Transporter's FERC Gas Tariff.

It is agreed, however, that the restrictions on assignment contained in this Article shall not in any way prevent either Party to the Contract from pledging or mortgaging its rights thereunder as security for its indebtedness.

ARTICLE VIII - LAW OF CONTACT

The interpretation and performance of this Contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to doctrines governing choice of law.

ARTICLE IX - PRIOR AGREEMENTS CANCELLED

Transporter and Shipper agree that this Contract, as of the date hereof, shall supersede and cancel the following contract(s) between the parties hereto:

Contract for Storage Service dated 9/1/93.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized agents.

TENNESSEE GAS PIPELINE COMPANY

By: [signature] CFS
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

By: George S. Billings
~~Agent and Attorney-in-Fact~~
George S. Billings

Title: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2362

EXHIBIT "A"
TO GAS STORAGE AGREEMENT
DATED SEPTEMBER 01, 1993
RATE SCHEDULE FS–MARKET AREA
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY, INC.

CONTRACT: 2362

CONTRACT MSQ: 45,300

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	1,128
060020	0	01	INJECTION	302

Contract No.: 2363

GAS STORAGE CONTRACT
(For Use Under Rate Schedule FS)

THIS Contract is made as of the 1st day of September 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation herein called "Transporter," and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, herein called "Shipper." Transporter and Shipper collectively shall be referred to herein as the "Parties."

ARTICLE I - SCOPE OF CONTRACT

Following the commencement of service hereunder, in accordance with the terms of Transporter's Rate Schedule FS (Market Area), and of this Agreement, Transporter shall receive for injection for Shipper's account a daily quantity of gas up to Shipper's Maximum Injection Quantity (on any day) and Maximum Storage Quantity of 162,411 Dth (on a cumulative basis) and on demand shall withdraw from Shipper's storage account and deliver to Shipper a daily quantity of gas up to Shipper's Maximum Daily Withdrawal Quantity of 3,824 Dth.

ARTICLE II - SERVICE POINT

The point or points at which the gas is to be tendered for delivery by Transporter to Shipper under this contract shall be at the storage service point at Transporter's Compressor Station 87.

ARTICLE III - PRICE

1. Shipper agrees to pay Transporter for all natural gas storage service furnished to Shipper hereunder, including compensation for system fuel and losses, at Transporter's legally effective rate or at any effective superseding rate applicable to the type of service specified herein. Transporter's present legally effective rate for said service is contained in Transporter's Rate Schedule FS as filed with the Federal Energy Regulatory Commission.

2. Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

3. Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FS, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE IV - INCORPORATION OF RATE SCHEDULE AND TARIFF PROVISIONS

This Agreement shall be subject to the terms of Transporter's Rate Schedule FS, as filed with the Federal Energy Regulatory Commission, together with the General Terms and Conditions applicable thereto (including any changes in said Rate Schedule or General Terms and Conditions as may from time to time be filed and made effective by Transporter).

ARTICLE V - TERM OF CONTRACT

This Agreement shall be effective as of September 1, 1993 and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Tennessee to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

ARTICLE VI - NOTICES

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under the Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER:	Tennessee Gas Pipeline Company P.O. Box 2511 Houston, TX 77252-2511 Attention: Transportation Marketing
SHIPPER:	
NOTICES:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: George S. Billings
BILLING:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE VII - ASSIGNMENT

Any company which shall succeed by purchase, merger or consolidation to the properties, substantially as an entirety, of Transporter or of Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this contract. Otherwise no assignment of the contract or any of the rights or obligations thereunder shall be made by Shipper, except pursuant to the General Terms and Conditions of Transporter's FERC Gas Tariff.

It is agreed, however, that the restrictions on assignment contained in this Article shall not in any way prevent either Party to the Contract from pledging or mortgaging its rights thereunder as security for its indebtedness.

ARTICLE VIII - LAW OF CONTACT

The interpretation and performance of this Contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to doctrines governing choice of law.

ARTICLE IX - PRIOR AGREEMENTS CANCELLED

Transporter and Shipper agree that this Contract, as of the date hereof, shall supersede and cancel the following contract(s) between the parties hereto:

Contract for Storage Service dated 9/1/93.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized agents.

TENNESSEE GAS PIPELINE COMPANY

By: ____________________
~~Byron S. Wright~~
Agent and Attorney-in-Fact

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

By: ____________________
~~Agent and Attorney-in-Fact~~

Title: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2363

EXHIBIT "A"
TO GAS STORAGE AGREEMENT
DATED SEPTEMBER 01, 1993
RATE SCHEDULE FS–MARKET AREA
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY, INC.

CONTRACT: 2363

CONTRACT MSQ: 162,411

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	3,824
060020	0	01	INJECTION	1,083

Contract No.: 2364

GAS STORAGE CONTRACT
(For Use Under Rate Schedule FS)

THIS Contract is made as of the 1st day of September 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation herein called "Transporter," and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, herein called "Shipper." Transporter and Shipper collectively shall be referred to herein as the "Parties."

ARTICLE I - SCOPE OF CONTRACT

Following the commencement of service hereunder, in accordance with the terms of Transporter's Rate Schedule FS (Market Area), and of this Agreement, Transporter shall receive for injection for Shipper's account a daily quantity of gas up to Shipper's Maximum Injection Quantity (on any day) and Maximum Storage Quantity of 179,911 Dth (on a cumulative basis) and on demand shall withdraw from Shipper's storage account and deliver to Shipper a daily quantity of gas up to Shipper's Maximum Daily Withdrawal Quantity of 3,684 Dth.

ARTICLE II - SERVICE POINT

The point or points at which the gas is to be tendered for delivery by Transporter to Shipper under this contract shall be at the storage service point at Transporter's Compressor Station 87.

ARTICLE III - PRICE

1. Shipper agrees to pay Transporter for all natural gas storage service furnished to Shipper hereunder, including compensation for system fuel and losses, at Transporter's legally effective rate or at any effective superseding rate applicable to the type of service specified herein. Transporter's present legally effective rate for said service is contained in Transporter's Rate Schedule FS as filed with the Federal Energy Regulatory Commission.

2. Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

3. Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FS, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE IV - INCORPORATION OF RATE SCHEDULE AND TARIFF PROVISIONS

This Agreement shall be subject to the terms of Transporter's Rate Schedule FS, as filed with the Federal Energy Regulatory Commission, together with the General Terms and Conditions applicable thereto (including any changes in said Rate Schedule or General Terms and Conditions as may from time to time be filed and made effective by Transporter).

ARTICLE V - TERM OF CONTRACT

This Agreement shall be effective as of September 1, 1993 and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Tennessee to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

ARTICLE VI - NOTICES

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under the Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER:	Tennessee Gas Pipeline Company P.O. Box 2511 Houston, TX 77252-2511 Attention: Transportation Marketing
SHIPPER:	
NOTICES:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: George S. Billings
BILLING:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE VII - ASSIGNMENT

Any company which shall succeed by purchase, merger or consolidation to the properties, substantially as an entirety, of Transporter or of Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this contract. Otherwise no assignment of the contract or any of the rights or obligations thereunder shall be made by Shipper, except pursuant to the General Terms and Conditions of Transporter's FERC Gas Tariff.

It is agreed, however, that the restrictions on assignment contained in this Article shall not in any way prevent either Party to the Contract from pledging or mortgaging its rights thereunder as security for its indebtedness.

ARTICLE VIII - LAW OF CONTACT

The interpretation and performance of this Contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to doctrines governing choice of law.

ARTICLE IX - PRIOR AGREEMENTS CANCELLED

Transporter and Shipper agree that this Contract, as of the date hereof, shall supersede and cancel the following contract(s) between the parties hereto:

Contract for Storage Service dated 9/1/93.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized agents.

TENNESSEE GAS PIPELINE COMPANY

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

By: ~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

DELTA NATURAL GAS COMPANY, INC.

By: George S. Billings
~~Agent and Attorney-in-Fact~~
George S. Billings

Title: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2364

EXHIBIT "A"
TO GAS STORAGE AGREEMENT
DATED SEPTEMBER 01, 1993
RATE SCHEDULE FS–MARKET AREA
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY, INC.

CONTRACT: 2364

CONTRACT MSQ: 179,911 .

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	3,684
060020	0	01	INJECTION	1,200

J'ville

Contract No.: 2365

GAS STORAGE CONTRACT
(For Use Under Rate Schedule FS)

THIS Contract is made as of the 1st day of September 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation herein called "Transporter," and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, herein called "Shipper." Transporter and Shipper collectively shall be referred to herein as the "Parties."

ARTICLE I - SCOPE OF CONTRACT

Following the commencement of service hereunder, in accordance with the terms of Transporter's Rate Schedule FS (Production Area), and of this Agreement, Transporter shall receive for injection for Shipper's account a daily quantity of gas up to Shipper's Maximum Injection Quantity (on any day) and Maximum Storage Quantity of 13,358 Dth (on a cumulative basis) and on demand shall withdraw from Shipper's storage account and deliver to Shipper a daily quantity of gas up to Shipper's Maximum Daily Withdrawal Quantity of 291 Dth.

ARTICLE II - SERVICE POINT

The point or points at which the gas is to be tendered for delivery by Transporter to Shipper under this contract shall be at the storage service point at Transporter's Compressor Station 87.

ARTICLE III - PRICE

1. Shipper agrees to pay Transporter for all natural gas storage service furnished to Shipper hereunder, including compensation for system fuel and losses, at Transporter's legally effective rate or at any effective superseding rate applicable to the type of service specified herein. Transporter's present legally effective rate for said service is contained in Transporter's Rate Schedule FS as filed with the Federal Energy Regulatory Commission.

2. Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

3. Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FS, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE IV - INCORPORATION OF RATE SCHEDULE AND TARIFF PROVISIONS

This Agreement shall be subject to the terms of Transporter's Rate Schedule FS, as filed with the Federal Energy Regulatory Commission, together with the General Terms and Conditions applicable thereto (including any changes in said Rate Schedule or General Terms and Conditions as may from time to time be filed and made effective by Transporter).

ARTICLE V - TERM OF CONTRACT

This Agreement shall be effective as of September 1, 1993 and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Tennessee to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

ARTICLE VI - NOTICES

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under the Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER:	Tennessee Gas Pipeline Company P.O. Box 2511 Houston, TX 77252-2511 Attention: Transportation Marketing
SHIPPER:	
NOTICES:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: George S. Billings
BILLING:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE VII - ASSIGNMENT

Any company which shall succeed by purchase, merger or consolidation to the properties, substantially as an entirety, of Transporter or of Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this contract. Otherwise no assignment of the contract or any of the rights or obligations thereunder shall be made by Shipper, except pursuant to the General Terms and Conditions of Transporter's FERC Gas Tariff.

It is agreed, however, that the restrictions on assignment contained in this Article shall not in any way prevent either Party to the Contract from pledging or mortgaging its rights thereunder as security for its indebtedness.

ARTICLE VIII - LAW OF CONTACT

The interpretation and performance of this Contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to doctrines governing choice of law.

ARTICLE IX - PRIOR AGREEMENTS CANCELLED

Transporter and Shipper agree that this Contract, as of the date hereof, shall supersede and cancel the following contract(s) between the parties hereto:

Contract for Storage Service dated 9/1/83.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized agents.

TENNESSEE GAS PIPELINE COMPANY

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

By: ______
~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

DELTA NATURAL GAS COMPANY, INC.

By: George S. Billings
~~Agent and Attorney-in-Fact~~
George S. Billings

Title: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2365

EXHIBIT "A"
TO GAS STORAGE AGREEMENT
DATED SEPTEMBER 01, 1993
RATE SCHEDULE FS-PRODUCTION AREA
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY, INC.

CONTRACT: 2365

CONTRACT MSQ: 13,358

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	291
060020	0	01	INJECTION	89

Contract No.: 2366

GAS STORAGE CONTRACT
(For Use Under Rate Schedule FS)

THIS Contract is made as of the 1st day of September 1993, by and between TENNESSEE GAS PIPELINE COMPANY, a Delaware corporation herein called "Transporter," and DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, herein called "Shipper." Transporter and Shipper collectively shall be referred to herein as the "Parties."

ARTICLE I - SCOPE OF CONTRACT

Following the commencement of service hereunder, in accordance with the terms of Transporter's Rate Schedule FS (Production Area), and of this Agreement, Transporter shall receive for injection for Shipper's account a daily quantity of gas up to Shipper's Maximum Injection Quantity (on any day) and Maximum Storage Quantity of 173,399 Dth (on a cumulative basis) and on demand shall withdraw from Shipper's storage account and deliver to Shipper a daily quantity of gas up to Shipper's Maximum Daily Withdrawal Quantity of 1,233 Dth.

ARTICLE II - SERVICE POINT

The point or points at which the gas is to be tendered for delivery by Transporter to Shipper under this contract shall be at the storage service point at Transporter's Compressor Station 87.

ARTICLE III - PRICE

1. Shipper agrees to pay Transporter for all natural gas storage service furnished to Shipper hereunder, including compensation for system fuel and losses, at Transporter's legally effective rate or at any effective superseding rate applicable to the type of service specified herein. Transporter's present legally effective rate for said service is contained in Transporter's Rate Schedule FS as filed with the Federal Energy Regulatory Commission.

2. Shipper agrees to reimburse Transporter for any filing or similar fees, which have not been previously paid by Shipper, which Transporter incurs in rendering service hereunder.

3. Shipper agrees that Transporter shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in (a) the rates and charges applicable to service pursuant to Transporter's Rate Schedule FS, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions applicable to those rate schedules. Transporter agrees that Shipper may protest or contest the aforementioned filings, or may seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary to assure Transporter just and reasonable rates.

ARTICLE IV - INCORPORATION OF RATE SCHEDULE AND TARIFF PROVISIONS

This Agreement shall be subject to the terms of Transporter's Rate Schedule FS, as filed with the Federal Energy Regulatory Commission, together with the General Terms and Conditions applicable thereto (including any changes in said Rate Schedule or General Terms and Conditions as may from time to time be filed and made effective by Transporter).

ARTICLE V - TERM OF CONTRACT

This Agreement shall be effective as of September 1, 1993 and shall remain in force and effect until November 1, 2000 ("Primary Term") and on a month to month basis thereafter unless terminated by either Party upon at least thirty (30) days prior written notice to the other Party; provided, however, that if the Primary Term is one year or more, then unless Shipper elects upon one year's prior written notice to Tennessee to request a lesser extension term, the Agreement shall automatically extend upon the expiration of the primary term for a term of five years; and shall automatically extend for successive five year terms thereafter unless Shipper provides notice described above in advance of the expiration of a succeeding term; provided further, if the FERC or other governmental body having jurisdiction over the service rendered pursuant to this Agreement authorizes abandonment of such service, this Agreement shall terminate on the abandonment date permitted by the FERC or such other governmental body.

ARTICLE VI - NOTICES

Except as otherwise provided in the General Terms and Conditions applicable to this Agreement, any notice under the Agreement shall be in writing and mailed to the post office address of the Party intended to receive the same, as follows:

TRANSPORTER:	Tennessee Gas Pipeline Company P.O. Box 2511 Houston, TX 77252-2511 Attention: Transportation Marketing
SHIPPER:	
NOTICES:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: George S. Billings
BILLING:	Delta Natural Gas Company, Inc. 3617 Lexington Road Winchester, KY 40391 Attention: Brian S. Ramsey

or to such other address as either Party shall designate by formal written notice to the other.

ARTICLE VII - ASSIGNMENT

Any company which shall succeed by purchase, merger or consolidation to the properties, substantially as an entirety, of Transporter or of Shipper, as the case may be, shall be entitled to the rights and shall be subject to the obligations of its predecessor in title under this contract. Otherwise no assignment of the contract or any of the rights or obligations thereunder shall be made by Shipper, except pursuant to the General Terms and Conditions of Transporter's FERC Gas Tariff.

It is agreed, however, that the restrictions on assignment contained in this Article shall not in any way prevent either Party to the Contract from pledging or mortgaging its rights thereunder as security for its indebtedness.

ARTICLE VIII - LAW OF CONTACT

The interpretation and performance of this Contract shall be in accordance with and controlled by the laws of the State of Texas, without regard to doctrines governing choice of law.

ARTICLE IX - PRIOR AGREEMENTS CANCELLED

Transporter and Shipper agree that this Contract, as of the date hereof, shall supersede and cancel the following contract(s) between the parties hereto:

Contract for Storage Service dated 9/1/93.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized agents.

TENNESSEE GAS PIPELINE COMPANY

By: ~~Byron S. Wright~~
~~Agent and Attorney-in-Fact~~

JAMES D. BUJNOCH
DIRECTOR, CENTRAL TEAM

DELTA NATURAL GAS COMPANY, INC.

By: ~~Agent and Attorney-in-Fact~~
George S. Billings

Title: Manager - Gas Supply

DATE: August 23, 1993

Contract No.: 2366

EXHIBIT "A"
TO GAS STORAGE AGREEMENT
DATED SEPTEMBER 01, 1993
RATE SCHEDULE FS–PRODUCTION AREA
BETWEEN
TENNESSEE GAS PIPELINE COMPANY
AND
DELTA NATURAL GAS COMPANY, INC.

CONTRACT: 2366

CONTRACT MSQ: 173,399

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	1,233
060020	0	01	INJECTION	1,156

AMENDMENT TO TRANSACTION CONFIRMATION

This Amendment ("Amendment") to Transaction Confirmation #314454 ("Transaction") is made and entered into as of the 1st Day November, 2017 ("Effective Date"), by and between Delta Natural Gas Company, Inc. as Buyer, and CenterPoint Energy Services, Inc. (as successor by merger to Atmos Energy Marketing, LLC) as Seller. Buyer and Seller may be referred to herein individually as a "Party" and collectively as the "Parties".

WITNESSETH:

WHEREAS, Buyer and Seller are parties to the Transaction which was entered into between the Parties under and pursuant to the terms of the Base Contract referenced in the Transaction; and

WHEREAS, the Parties desire to amend and modify certain terms and conditions of the Transaction all as more particularly hereinafter provided.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the Parties agree to and do hereby amend the Transaction as follows:

AMENDMENT:

1. Commencing on the Effective Date of this Amendment, the Delivery Period of this Transaction is hereby extended through and including April 30, 2021. Thereafter, the Delivery Period will renew for successive two (2) year periods unless terminated by either Party upon written notice given not less than sixty (60) Days prior to the end of the Delivery Period.

2. Unless otherwise specifically defined in this Amendment, capitalized terms used in this Amendment shall have the meaning given thereto in the Transaction and the Base Contract (as referenced in the Transaction).

3. Except as herein modified, or amended, all terms and conditions of the Transaction remain in full force and effect.

IN WITNESS WHEREOF, the Parties have executed this Amendment as of the date first written above in multiple counterparts, each of which constitutes an original.

DELTA NATURAL GAS COMPANY, INC.

By: Brian Ramsey
Brian Ramsey
VP - Transmission + Gas Supply

CENTERPOINT ENERGY SERVICES, INC.

By: Rob Ellis
Rob Ellis
Vice President

EXHIBIT A

Atmos Energy Marketing, LLC
13430 Northwest Freeway, Suite 400, Houston, TX 77040

TRANSACTION CONFIRMATION FOR IMMEDIATE DELIVERY

Date:	Transaction Confirmation #: 314454
Seller: Atmos Energy Marketing, LLC 2000 Warrington Way, Suite 230 Louisville, KY 40222 **Attn:** Trevor Atkins **Phone:** (502) 326-1381 **Fax:** (502) 326-1411 **Email:** trevor.atkins@atmosenergy.com	**Buyer:** Delta Natural Gas Company Inc. 3617 Lexington Road Winchester, KY 40391-9797 **Attn:** Brian Ramsey **Phone:** (859) 744-6171 Ext. 158 **Fax:** (859) 744-3623 **Email:** bramsey@deltagas.com

Delivery Period:	Begin:	May 1, 2010	End:	April 30, 2011
Transporter:	TETCO			
Service Level:	Firm			
Delivery Point:	73131 and 73196			
(If a pooling point is used, list a specific geographic location and pipeline location)				

Begin Flow Date	End Flow Date	Contract Quantity MMBtus/Day	Contract Price (US$/MMBtu)		
			Index Price	Fuel	Transportation
May 1, 2010	April 30, 2011	Up to 1,000	NYMEX Last Day Settle	TETCO ELA-M2	$0.38

Special Conditions: 1) At the expiration of the Delivery Period, this Transaction Confirmation shall automatically extend for twelve (12) successive months unless terminated on sixty (60) days written notice by either party.

This Transaction Confirmation constitutes and confirms an agreement by the parties to sell and purchase gas in accordance with the terms described herein and is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer .

Please confirm that the foregoing correctly sets forth the terms of our agreement with respect to this transaction by signing in the space provided below and returning a copy of the executed confirmation to us. Your failure to execute and return this confirmation or to advise us of any errors by the time specified in the Base Contract or in the NAESB, or, if not so specified, before the gas begins to flow, shall constitute your acceptance of these terms.

AGREED TO AND ACCEPTED: SELLER **Atmos Energy Marketing, LLC**	AGREED TO AND ACCEPTED: BUYER **Delta Natural Gas Company Inc.**
By:	By:
Printed Name:	Printed Name: Brian Ramsey
Title:	Title: VP - Transmission + Gas Supply

SYMBOLS: Unless expressly provided otherwise all prices are per MMBtu of gas. "GD" means Gas Daily ® Midpoint or Index, as applicable, for the applicable delivery day for the specified location. "IF" means Inside F.E.R.C.s Gas Market Report, Index, first publication for the month, for the delivery month for the specified location. "NGW" means Natural Gas Week ®. "NGI" means Natural Gas Intelligence. "NYMEX" means New York Mercantile Exchange. "KCBOT" means Kansas City Board of Trade.

APPROVED
By tratkins at 2:57 pm, Feb 24, 2010

APPROVED
By joerose at 3:48 pm, Feb 24, 2010

AMENDMENT TO GAS SALES AGREEMENT

THIS AMENDMENT TO GAS SALES AGREEMENT ("Amendment") is made and entered into as of the 1st day of November, 2017 ("Effective Date"), by and between the DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as Buyer, and CENTERPOINT ENERGY SERVICES, INC. (as successor by merger to Atmos Energy Marketing, LLC), a Delaware corporation, hereinafter referred to as Seller. Buyer and Seller may be referred to herein individually as a "Party" and collectively as the "Parties".

WITNESSETH:

WHEREAS, Buyer and Seller are parties to that certain Gas Sales Agreement dated **May 1, 2000** (the "Agreement") as previously amended; and

WHEREAS, the Parties desire to further amend the Agreement as hereinafter set forth.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the Parties agree to and do hereby modify the Agreement as hereinafter provided:

1. Commencing on the Effective Date of this Amendment, the term of this Agreement is hereby extended through and including April 30, 2021. Thereafter, the term will renew for successive two (2) year periods unless terminated by either Party upon written notice given not less than sixty (60) Days prior to the end of the current term.

2. Unless otherwise specifically defined in this Amendment, capitalized terms used herein shall have the meaning given thereto in the Gas Sales Agreement.

3. Except as herein modified or amended, all terms and provisions of the Gas Sales Agreement, as previously amended, remain in full force and effect.

IN WITNESS WHEREOF, the parties have executed this Amendment as of the Effective Date first written above in multiple counterparts, each of which constitutes and original.

DELTA NATURAL GAS COMPANY, INC.

By: Brian Ramsey
Name: Brian Ramsey
Title: VP – Transmission + Gas Supply

CENTERPOINT ENERGY SERVICES, INC.

By: Rob Ellis
Rob Ellis, Vice President

Exhibit 2-4

5/18/00
original to
Caron +
customer

GAS SALES AGREEMENT

BY AND BETWEEN

DELTA NATURAL GAS COMPANY, INC.

AS BUYER

AND

WOODWARD MARKETING, L.L.C.

AS SELLER

GAS SALES AGREEMENT

THIS GAS SALES AGREEMENT made and entered into to be effective the 1st day of May, 2000, by and between the DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as "Buyer", and WOODWARD MARKETING, L.L.C., a Delaware corporation, hereinafter referred to as "Seller".

WITNESSETH THAT:

WHEREAS, Buyer and Seller have entered into a Gas Sales Agreement ("Agreement"), to be effective May 1, 2000, providing for the purchase by the Buyer and sale by Seller on a firm basis of 100% of the natural gas requirements of Buyer's residential and small commercial customers and providing for certain other services of Seller to Buyer, and

WHEREAS, for the purpose of setting forth the terms of said agreements, the parties have agreed to this Agreement.

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

ARTICLE I
DEFINITIONS

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

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

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

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

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

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

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

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

1.8 The Term "MEAC" means Municipal Energy Acquisition Corporation, an energy acquisition corporation as defined in Title 7, Chapter 39 of the Tennessee Code annotated, as amended.

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

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

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

ARTICLE II
QUANTITY AND NOMINATIONS

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

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

2.3 Remedies for Failure to Deliver and Receive

2.3.1 Seller's Failure to Deliver

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

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

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

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

2.3.3 Failure to Take - If Buyer fails to receive and purchase its full requirements in accordance with Section 2.1 above, then Buyer will pay Seller $0.035 per MMBtu plus the difference in the price stated in 3.1.1 and Gas Daily TGP 500 leg average index times the difference between (a) its full requirements and (b) the quantities actually taken by Buyer during the applicable seasonal period.

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

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

2.5 MEAC Volumes - Buyer shall have the option to contract with MEAC for a portion of their volumes. Buyer hereby appoints Seller as agent, for the term of this Agreement, to administer the MEAC Gas Supply Agreement. Buyer will be required to advise Seller of the MEAC Volumes to be nominated and purchased under the MEAC Gas Supply Agreement and transported on a transportation Contract with Tennessee, either on a daily basis or pursuant to general guidelines provided by Buyer and agreed to by Seller. Except for negligence or willful misconduct of Seller, Seller will not be responsible for the loss or damage associated with the nomination of the MEAC Volumes by Seller hereunder and Buyer will defend, indemnify and hold harmless Seller against any such loss or damage, including without limitation any loss or damage arising out of Buyer's contracts to purchase the MEAC Volumes.

ARTICLE III
PRICE

3.1 Commodity Price for All Other Quantities Within MDQ

3.1.1 City-gate Service - The price for each MMBtu of gas sold and delivered hereunder at the Delivery Point(s), except for the MEAC volumes under 2.5, up to the MDQ shall be priced at the TGP Zone 1 index as published in the first of the month Inside

F.E.R.C's Gas Market report minus $0.06 / MMBtu. The pricing under this contract shall be redetermined in the event that Buyer's storage contracts are altered.

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

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

3.3 Transportation and Storage Costs – In addition to payments made above, Buyer shall reimburse Seller for (1) all demand or reservation charges or surcharges paid by Seller under the Firm Transportation Contracts and Firm Storage Contracts released and delegated to Seller in accordance with Article V below, including without limitation any demand transition cost surcharges, (2) all commodity or volumetric charges or surcharges under the Firm Transportation Contracts and Firm Storage Contracts that are associated with the gas sold by Seller hereunder, including without limitation any volumetric transition costs, GRI charges, or ACA charges that are incurred under such contracts or any injection or withdrawal charges that are incurred under the Firm Storage Contracts that are required to build inventory levels for Buyer or to serve Buyer's daily requirements, (3) any transportation costs paid by Seller to Tennessee to transport the gas delivered to and from storage under the Firm Storage Contract, to the interconnection of Tennessee's facilities (herein referred to as the "IT Transportation Contract"), (4) any fuel and loss costs incurred under the Firm Transportation Contracts, the IT Transportation Contract and the Firm Storage Contracts, such costs to be equal to the amount of fuel and loss quantities that Seller provided to Tennessee pursuant to such contracts during the applicable month times the Commodity Price and (5) any other costs, expenses or charges incurred by Seller under such contracts (as such contracts and the associated tariff provisions and charges may change from time to time) that would have been incurred by Buyer if Buyer had administered such contracts. To the extent that Seller is reimbursed by Buyer in accordance with this section, Seller will indemnify and hold Buyer harmless from any claims made by Tennessee for the failure to make payments under the Firm Transportation Contracts or the Firm Storage Contracts. Seller shall be responsible for any charges incurred in connection with its utilization of Buyer's Firm Transportation or Firm Storage Contracts for purposes other than providing gas supply to Buyer. Seller shall credit Buyer 90% of revenue derived from third-party release of Buyer's Firm capacity as posted on Transporter's Electronic Bulletin Board.

ARTICLE IV
DELIVERY POINTS

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

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

ARTICLE V
TRANSPORTATION AND STORAGE ARRANGEMENTS

5.1 Transportation and Storage Arrangements

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

5.2 Responsibility for Firm Transportation and Storage Contracts

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

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

5.2.3 Penalty Responsibility - Buyer will be required to reimburse Seller for (1) unauthorized overrun penalties associated with takes in excess of the maximum daily quantities under the Firm Transportation and Storage Contracts, (2) any penalties or charges that are imposed by Tennessee due to Buyer's failure to comply with a directive of the pipeline limiting quantities to less than Buyers contracted maximum daily quantities.

5.3 Telemetry - Seller will have the right, but not the obligation to install, at its expense, telemetry or other data linkage equipment that will monitor Buyer's natural gas requirements on its distribution system, Buyer will provide the necessary space to install such equipment and will provide access to maintain, repair and remove such equipment, all at no cost to Seller. Buyer shall authorize Seller to access Tennessee telemetry readings on Buyer's behalf, so long as Buyer is not required to give up its current access to Tennessee's telemetry readings.

5.3.1 Projected Requirements - Buyer will provide Seller information concerning any known or expected events pertaining to the non-residential and commercial customers of the Buyer that will cause material changes in Buyer's daily natural gas requirements. Buyer will cooperate with Seller to ensure that nominations (including any necessary adjustments thereto) are made timely to Tennessee and that such nominations reflect the actual expected deliveries and receipts.

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

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

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

ARTICLE VI
TERM OF AGREEMENT

6.1 Primary Term - This Agreement shall become effective on May 1, 2000 (herein referred to as the "Effective Date") and shall continue in full force and effect for a primary term of three years through April 30, 2003. At the expiration of the primary term, this Agreement will be extended for an additional year, unless on or before 60 days prior to the expiration of the primary term, either Party gives written notice to the other Party that it does not desire to extend the primary term.

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

ARTICLE VII
TITLE AND TAXES

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

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

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

ARTICLE VIII
QUALITY AND PRESSURE

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

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

ARTICLE IX
MEASUREMENT AND TESTS

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

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

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

ARTICLE X
PROCESSING

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

ARTICLE XI
BILLING AND PAYMENT

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

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

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

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

ARTICLE XII
REGULATORY BODIES

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

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

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

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

ARTICLE XIII
FORCE MAJEURE

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

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

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

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

ARTICLE XIV
ARBITRATION

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

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

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

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

ARTICLE XV
MISCELLANEOUS

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

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

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

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

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

Buyer:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391
Attention: Mr. Brian Ramsey
Phone: 606-744-6171 Ext.158
Fax: 606-744-3623
Email: bramsey@deltagas.com

Seller: Nominations:

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

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

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

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

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

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

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

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

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

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

IN WITNESS WHEREOF, this Agreement is executed in multiple counterparts, each of which is an original as of April 24, 2000.

DELTA NATURAL GAS COMPANY, INC.	WOODWARD MARKETING, L.L.C.
By: Alan L. Heath	By: Rob Ellis
Name: ALAN L. HEATH	Name: ROB ELLIS
Title: V.P. OPS. & ENG.	Title: SR. VICE PRESIDENT

EXHIBIT A

BUYER: Delta Natural Gas Company, Inc.

Pursuant to the Gas Sales Agreement between Seller and Buyer, the Tennessee Gas Pipeline Company delivery point(s) for the natural gas service are as follows:

Delivery Points	Meter Number
Nicholasville	020248
Berea	020208
Jeffersonville	020430
Salt Lick	020212
Farmers	020462
Kinder Hilda	020733
Westbend	020813
Richmond	020895

EXHIBIT B

BUYER: Delta Natural Gas Company, Inc.

Pursuant to the Gas Sales Agreement between Seller and Buyer, the Tennessee Gas Pipeline Company Pipeline and Storage contracts are as follows:

TGP Pipeline Capacity:

	FT-G	FT-A	Total
January	16,211	1,400	17,611
February	16,211	1,400	17,611
March	11,050	1,400	12,450
April	8,075	1,400	9,475
May	6,150	1,400	7,550
June	4,276	1,400	5,676
July	4,248	1,400	5,648
August	4,248	1,400	5,648
September	4,246	1,400	5,826
October	7,144	1,400	8,544
November	10,275	1,400	11,675
December	16,211	1,400	17,611

TGP Storage Capacity:

	MSQ	MDWQ	MDIQ
Production Area:	186,757	1,524	1,245
Market Area:	387,622	8,636	2,585

AMENDMENT TO GAS SALES AGREEMENT

THIS AMENDMENT TO GAS SALES AGREEMENT ("Amendment") is made and entered into as of the 1st day of November, 2017 ("Effective Date"), by and between the DELTA NATURAL GAS COMPANY, INC., a Kentucky corporation, hereinafter referred to as Buyer, and CENTERPOINT ENERGY SERVICES, INC. (as successor by merger to Atmos Energy Marketing, LLC), a Delaware corporation, hereinafter referred to as Seller. Buyer and Seller may be referred to herein individually as a "Party" and collectively as the "Parties".

WITNESSETH:

WHEREAS, Buyer and Seller are parties to that certain Gas Sales Agreement dated **May 1, 2003** (the "Agreement") as previously amended; and

WHEREAS, the Parties desire to further amend the Agreement as hereinafter set forth.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the Parties agree to and do hereby modify the Agreement as hereinafter provided:

1. Commencing on the Effective Date of this Amendment, the term of this Agreement is hereby extended through and including April 30, 2021. Thereafter, the term will renew for successive two (2) year periods unless terminated by either Party upon written notice given not less than sixty (60) Days prior to the end of the current term.

2. Unless otherwise specifically defined in this Amendment, capitalized terms used herein shall have the meaning given thereto in the Gas Sales Agreement.

3. Except as herein modified or amended, all terms and provisions of the Gas Sales Agreement, as previously amended, remain in full force and effect.

IN WITNESS WHEREOF, the parties have executed this Amendment as of the Effective Date first written above in multiple counterparts, each of which constitutes and original.

DELTA NATURAL GAS COMPANY, INC.

By: Brian Ramsey

Name: Brian Ramsey

Title: VP - Transmission & Gas Supply

CENTERPOINT ENERGY SERVICES, INC.

By: Rob Ellis

Rob Ellis, Vice President

Exhibit 2-6

GAS SALES AGREEMENT

BY AND BETWEEN

DELTA NATURAL GAS COMPANY, INC.

AS BUYER

AND

WOODWARD MARKETING, L.L.C.

AS SELLER

GAS SALES AGREEMENT

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

WITNESSETH THAT:

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

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

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

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

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

ARTICLE I
DEFINITIONS

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

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

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

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

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

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

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

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

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

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

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

ARTICLE II
QUANTITY AND NOMINATIONS

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

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

2.3 Remedies for Failure to Deliver and Receive

2.3.1 Seller's Failure to Deliver

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

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

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

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

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

2.3.4 Exclusive Remedy - The Parties agree that the actual losses incurred by Buyer as a result of Seller's failure to deliver quantities and incurred by Seller as a result of

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

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

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

ARTICLE III
PRICE

3.1 Commodity Price for All Other Quantities Within MDQ

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

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

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

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

ARTICLE IV
DELIVERY POINTS

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

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

ARTICLE V
TRANSPORTATION AND STORAGE ARRANGEMENTS

5.1 Transportation and Storage Arrangements

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

Buyer will cooperate with Seller to make such necessary elections as designated by Seller. Similarly, Buyer will cooperate with Seller to make any amendments to the contracts requested by Seller to become effective on the Effective Date of this Agreement to the extent said amendments do not adversely affect, in Buyer's sole opinion, Buyer's costs or Buyer's level or quality of service. In the event of any supplementation or contradiction between the Blanket Authorization Agreement and this Agreement, the terms of this Agreement shall control and govern the rights, obligations, and liabilities of Seller and Buyer.

5.2 Responsibility for Firm Transportation and Storage Contracts

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

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

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

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

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

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

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

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

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

ARTICLE VI
TERM OF AGREEMENT

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

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

ARTICLE VII
TITLE AND TAXES

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

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

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

ARTICLE VIII
QUALITY AND PRESSURE

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

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

ARTICLE IX
MEASUREMENT AND TESTS

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

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

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

ARTICLE X
PROCESSING

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

ARTICLE XI
BILLING AND PAYMENT

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

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

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

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

ARTICLE XII
REGULATORY BODIES

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

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

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

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

ARTICLE XIII
FORCE MAJEURE

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

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

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

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

ARTICLE XIV
ARBITRATION

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

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

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

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

ARTICLE XV
MISCELLANEOUS

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

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

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

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

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

Buyer:

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

Seller:	Nominations:
Woodward Marketing, L.L.C	Woodward Marketing, L.L.C.
377 Riverside Drive, Suite 109	11251 Northwest Freeway, Suite 400
Franklin, TN 37064	Houston, TX 77092
Attention: Mr. Rob Ellis	Attention: Mr. Rick Sullivan
Phone: 615-595-2878	Phone: 713-688-7771
Fax: 615-794-0947	Fax: 713-688-5124

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

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

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

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

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

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

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

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

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

DELTA NATURAL GAS COMPANY, INC.

By: ____________

Name: George S Billings

Title: Mgr - Gas Supply

WOODWARD MARKETING, L.L.C.

By: ____________

Name: Rob Ellis

Title: SR. Vice President

EXHIBIT A

BUYER: Delta Natural Gas Company, Inc.

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

All volumes in Dth

Columbia Gulf Transmission Pipeline Capacity:

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

Columbia Gas Transmission Pipeline Capacity:	GTS	
Delta-Winchester Contract No.	37815	4950
Delta-Stanton Contract No.	37814	2530
Delta-Cumberland Contract No.	37813	5400

Columbia Gas Transmission Storage Capacity:	CAPACITY
Delta-Winchester	162857
Delta-Stanton	83254
Delta-Cumberland	177662

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

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: May 1, 2013. The parties to this Base Contract are the following:

Delta Natural Gas Company	and Midwest Energy Services, LLC
3617 Lexington Road, Winchester, KY 40391	PO Box 8227, Zanesville, OH 43702-8227
Duns Number: 00-777-9408	Duns Number: 07-878-2400
Contract Number:	Contract Number: DGAS01-2013-00
U.S. Federal Tax ID Number: 61-0458329	U.S. Federal Tax ID Number: 46-2159905
Notices:	
Delta Natural Gas Company	Midwest Energy Services, LLC
Attn: Brian S. Ramsey	Attn: Brian R. Jonard
Phone: 859-744-6171 Ext 158 Fax: 866-895-6155	Phone: 740-319-9677 Fax:
Confirmations:	
Delta Natural Gas Company	Midwest Energy Services, LLC
Attn: Brian S. Ramsey	Attn: Brian R. Jonard
Phone: 859-744-6171 Ext 158 Fax: 866-895-6155	Phone: 740-319-9677 Fax:
Invoices and Payments:	
Invoices: Delta Natural Gas Company.	Midwest Energy Services, LLC
Attn: Steven R. York	Attn: Brian R. Jonard
Payments: Attn: Accounts Receivable	Payments: Brian R.Jonard
Phone: 859-744-6171 Ext 131 Fax: 800-482-7623	Phone: 740-319-9677 Fax:
Wire Transfer or ACH Numbers (if applicable):	
BANK:	BANK:
ABA:	ABA:
ACCT:	ACCT:
Other Details:	Other Details:

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select only one box from each section:

Section 1.2 Transaction Procedure	■ Oral (default) ☐ Written	**Section 7.2** Payment Date	☐ 25th Day of Month following Month of delivery (default) ■ 20th Day of Month following Month of delivery
Section 2.5 Confirm Deadline	■ 2 Business Days after receipt (default) ☐ _____ Business Days after receipt	**Section 7.2** Method of Payment	■ Wire transfer (default) or ■ Automated Clearinghouse Credit (ACH) ☐ Check
Section 2.6 Confirming Party	☐ Seller (default) ☐ Buyer ■ Midwest Energy Services, LLC	**Section 7.7** Netting	■ Netting applies (default) ☐ Netting does not apply
Section 3.2 Performance Obligation	☐ Cover Standard (default) ■ Spot Price Standard *Note: The following Spot Price Publication applies to both of the immediately preceding.*	**Section 10.3.1** Early Termination Damages	■ Early Termination Damages Apply (default) ☐ Early Termination Damages Do Not Apply
		Section 10.3.2 Other Agreement Setoffs	☐ Other Agreement Setoffs Apply (default) ■ Other Agreement Setoffs Do Not Apply
Section 2.26 Spot Price Publication	■ Gas Daily Midpoint (default) ☐ ________________	**Section 14.5** Choice Of Law	Ohio
Section 6 Taxes	■ Buyer Pays At and After Delivery Point (default) ☐ Seller Pays Before and At Delivery Point	**Section 14.10** Confidentiality	■ Confidentiality applies (default) ☐ Confidentiality does not apply
Special Provisions Number of sheets attached: None Addendum(s): None			

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

Delta Natural Gas Company	Midwest Energy Services, LLC
Party Name	Party Name
By *Brian Ramsey*	By *Brian R Jonard*
Name: Brian S. Ramsey	Name: Brian R. Jonard
Title: Vice President – Transmission & Gas Supply	Title: Manager

General Terms and Conditions
Base Contract for Sale and Purchase of Natural Gas

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.7.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract. However, nothing herein shall be construed as a waiver of any objection to the admissibility of such evidence.

SECTION 2. DEFINITIONS

The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.1. "Alternative Damages" shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.2. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.3. "British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

2.4. "Business Day" shall mean any day except Saturday, Sunday or Federal Reserve Bank holidays.

2.5. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.6. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.7. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation.

2.8. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.9. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.10. "Cover Standard", as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.11. "Credit Support Obligation(s)" shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, a performance bond, guaranty, or other good and sufficient security of a continuing nature.

2.12. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.

2.13. "Delivery Period" shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.14. "Delivery Point(s)" shall mean such point(s) as are agreed to by the parties in a transaction.

2.15. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.16. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm", provided that a party's excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.17. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.18. "Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.19. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

2.20. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.21. "MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

2.22. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.23. "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.24. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.25. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.26. "Spot Price " as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.27. "Transaction Confirmation" shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.28. "Termination Option" shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.29. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the "Cover Standard" or the "Spot Price Standard" as indicated on the Base Contract.
Cover Standard:
3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the sole and exclusive remedy of the performing party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s). Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.
Spot Price Standard:
3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.

Buyer Pays At and After Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

Seller Pays Before and At Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 14.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payments and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party ("X") has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party ("Y") (including, without limitation, the occurrence of a material change in the creditworthiness of Y), X may demand Adequate Assurance of Performance. "Adequate Assurance of Performance" shall mean sufficient security in the form, amount and for the term reasonably acceptable to X, including, but not limited to, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or a performance bond or guaranty (including the issuer of any such security).

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; or (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law or that are, in the reasonable opinion of the Non-Defaulting Party, commercially impracticable to liquidate and terminate ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is reasonably practicable, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.

Early Termination Damages Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions).

For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.

Early Termination Damages Do Not Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract.

The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.

Other Agreement Setoffs Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff (i) any Net Settlement Amount owed to the Non-Defaulting Party against any margin or other collateral held by it in connection with any Credit Support Obligation relating to the Contract; or (ii) any Net Settlement Amount payable to the Defaulting Party against any amount(s) payable by the Defaulting Party to the Non-Defaulting Party under any other agreement or arrangement between the parties.

Other Agreement Setoffs Do Not Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount owed to the Non-Defaulting Party against any margin or other collateral held by it in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of such amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Agreement; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6 and Section 10, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 14. MISCELLANEOUS

14.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

14.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

14.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

14.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

14.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

14.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

14.7. There is no third party beneficiary to this Contract.

14.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

14.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

14.10. Unless the parties have elected on the Base Contract not to make this Section 14.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract , (iii) to the extent necessary to implement any transaction, or (iv) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure, and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

14.11 The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties.

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Date: ______________________, _____
Transaction Confirmation #: ______________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated ______________________. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	BUYER:
______________________	______________________
______________________	______________________
______________________	______________________
Attn: ______________________	Attn: ______________________
Phone: ______________________	Phone: ______________________
Fax: ______________________	Fax: ______________________
Base Contract No. ______________________	Base Contract No. ______________________
Transporter: ______________________	Transporter: ______________________
Transporter Contract Number: ______________	Transporter Contract Number: ______________

Contract Price: $______/MMBtu or ____

Delivery Period: Begin: ____________, ____ End: __________, ____

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
_______ MMBtus/day	_______ MMBtus/day Minimum	Up to ______ MMBtus/day
☐ EFP	_______ MMBtus/day Maximum	
	subject to Section 4.2. at election of	
	☐ Buyer or ☐ Seller	

Delivery Point(s): ________________________
(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions:

Seller: ______________________	Buyer: ______________________
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

Exhibit 2-8

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Midwest Energy Services, LLC

Trade Date: June 27, 2018

Transaction Confirmation #: Col Gulf

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated May 1, 2013. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	BUYER:
Midwest Energy Services, LLC	Delta Natural Gas Company
PO Box 8227	3617 Lexington Road
Zanesville, Ohio 43702-8227	Winchester, KY 40391
Attn: Brian R Jonard	Attn: Donald C. Cartwright
Phone: 740-915-4717	Phone: 859-744-6171 ext 1169
Email: bjonard@midwestenergyllc.com	Fax: 866-895-6155
Base Contract No. DGAS01-2013-00	Base Contract No.
Transporter: N/A	Transporter: N/A
Transporter Contract Number: N/A	Transporter Contract Number: N/A

Contract Price: IFERC Columbia Gulf – Mainline, plus $0.055 per MMBtu

Delivery Period: Begin: July 1, 2018 End: August 1, 2018

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
4,500 MMBtus/day	______ MMBtus/day Minimum ______ MMBtus/day Maximum subject to Section 4.2. at election of ☐ Buyer or ☐ Seller	Up to _____ MMBtus/day

Delivery Point(s): AGG Point - DELTA

(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions:

Seller: MIDWEST ENERGY SERVICES, LLC	Buyer: DELTA NATURAL GAS COMPANY
By: Brian R Jonard	By:
Name: Brian R. Jonard	Name: Donald C. Cartwright
Title: Manager	Title: Manager – Gas Control Operations
Date: June 27, 2018	Date:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797

www.deltagas.com

PHONE: 859-744-6171
FAX: 859-744-3623

June 11, 2012

Mr. Mike Robinson
Vinland Energy Operations
2704 Old Rosebud Road, Suite 320
Lexington, KY 40509

Dear Mike:

Upon acceptance by Vinland Energy Operations this letter shall serve as an addendum to the Agreement dated October 28, 1999, as amended, by and between Delta Natural Gas Company, Inc. (Buyer) and Vinland Energy Operations (Seller) and will become effective July 1, 2012. The change shall be as follows:

1) Article VI. Price. Paragraph 6.1. For each Dth of gas sold and delivered hereunder, Buyer agrees to pay Seller the Contract Price. The Contract Price shall equal 100% of the Columbia Gas Transmission Corp. Appalachia index as published monthly in *Inside FERC's* Gas Market Report.

All other terms and conditions of the above referenced Agreement shall remain unchanged. Please execute and return to me for our records.

Sincerely,

Brian Ramsey

Brian S. Ramsey
Vice President
Transmission & Gas Supply

Accepted by:

VINLAND ENERGY OPERATIONS

BY: Michael J. Robinson

TITLE: President & CEO

DATE: 19 June 12

CONTRACT FOR GAS SALES AND DELIVERY SERVICE
OFF OF GATHERING FACILITIES

between

COLUMBIA NATURAL RESOURCES, INC.

and

DELTA NATURAL GAS COMPANY, INC.

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CONTRACT FOR
GAS SALES AND DELIVERY SERVICE

THIS AGREEMENT, made and entered into this 25th day of October, 1999, by and between DELTA NATURAL GAS COMPANY, INC. ("Buyer"), a Kentucky corporation with offices located at 3617 Lexington Road, Winchester, Kentucky 40391-9797 and COLUMBIA NATURAL RESOURCES, INC. ("Seller"), a Texas corporation with offices located at 900 Pennsylvania Avenue, P.O. Box 6070, Charleston, West Virginia 25362-0070.

RECITALS

WHEREAS, Seller owns and controls certain Gathering Facilities located in Kentucky; and

WHEREAS, Buyer provides regulated natural gas utility service to certain customers in the State of Kentucky that historically has been achieved by deliveries through Town Border Stations or Dual Purpose Meters (collectively "Meter(s)") that are located along, connected to, or otherwise depend upon the Gathering Facilities to physically receive gas; and

WHEREAS, Seller has adequate supplies of Gas to meet Buyer's existing needs and desires to sell Gas to Buyer; and

WHEREAS, Buyer and Seller desire to enter into this Agreement intending for Buyer to obtain reliable and economic gas sales and delivery service to continue to meet its utility service obligations to customers connected to the Gathering Facilities acquired by Seller;

NOW THEREFORE, in consideration of the mutual covenants contained herein, the parties hereto, intending to be legally bound, do hereby agree as follows:

ARTICLE I -- PURPOSE AND PROCEDURES

1.1 This Contract establishes the terms governing the sales and deliveries of Gas by Seller and the respective obligations of the parties during the period this Contract is in effect.

1.2 The entire Contract between the parties shall be governed by the provisions contained in this Agreement, including attachments incorporated herein.

ARTICLE II -- DEFINITIONS

Unless another definition is expressly stated, the following terms and abbreviations when used in this Contract will mean as follows:

2.1 "Agreed Index Price" shall mean the Index price of spot Gas delivered to Columbia Gas Transmission Corporation, Appalachia (West Virginia, Ohio, Kentucky) as reported in the first publication each Month of *Inside F.E.R.C.'s Gas Market Report*.

2.2 "Attachment A" shall mean the document attached to this Contract, as updated from time to time, and incorporated herein which lists the Meter(s) through which deliveries of Gas shall be made pursuant to this Contract. Attachment A shall identify a Maximum Daily Quantity (MDQ) for each Town Border Station and an aggregate MDQ for the Dual Purpose Meters.

2.3 "Billing Cycle" shall mean the interval between the times when Buyer reads the meters and/or changes the chart on the Meter(s) at the Delivery Point(s) identified in Attachment A herein. The Billing Cycle shall be identified by reference to the calendar Month in which the Meter(s) are read and/or the chart(s) removed.

2.4 "British Thermal Unit" or "Btu" shall mean the amount of heat required to raise the temperature of one pound of pure water from 59° Fahrenheit to 60° Fahrenheit at a constant pressure of 14.73 pounds per square inch absolute (psia).

2.5 "Business Day" shall mean any day except Saturday, Sunday or bank holidays.

2.6 "Buyer's Customers" shall mean the industrial, commercial and residential customers to whom Buyer provides natural gas utility services through Meters located along or connected to the Gathering Facilities and identified in Attachment A, attached hereto and expressly made a part hereof.

2.7 "Contract" shall mean this legally binding document setting forth the agreement and understanding held by the parties hereto, including all attachments, exhibits and appendices attached or otherwise required as supplements hereto.

2.8 "Contract Quantity" shall mean the total of all Maximum Daily Quantities listed for the Meters designated in Attachment A.

2.9 "Cubic Foot" and "Standard Cubic Foot" shall mean that quantity of Gas that occupies one cubic foot of volume at a pressure of fourteen and seventy-three one-hundredths pounds per square inch absolute (14.73 psia) and a temperature of sixty degrees Fahrenheit (60° F).

2.10 "Day" shall mean a period of twenty-four (24) consecutive hours commencing at 10:00 A.M. Eastern Standard Time (EST) or Eastern Daylight Time (EDT),as applicable.

2.11 “Dekatherm” or “Dth” shall mean one million British Thermal Units.

2.12 "Delivery Point(s)" or “Points of Delivery” shall mean the interconnection of Buyer’s and Seller’s facilities.

2.13 "Gas" shall mean any mixture of hydrocarbons or of hydrocarbons and non-combustible gases in a gaseous state consisting essentially of methane which conforms with Article VIII.

2.14 “Gathering Facilities” shall mean the pipelines and related facilities that are utilized to gather and deliver natural gas to Buyer and to other pipelines.

2.15 “Maximum Daily Quantity” or “MDQ” shall mean the maximum quantity of Gas that the Seller agrees to sell and deliver to Buyer at the Points of Delivery.

2.16 "Mcf" shall mean one thousand (1,000) Cubic Feet of Gas.

2.17 "Meter(s)" shall mean the Gas metering stations as set forth in Attachment A.

a. “Town Border Station” or “Town Border Measuring Station” shall mean a metered point of delivery, uniquely identified by a meter number. Such meters and their identifying numbers shall be listed individually on Attachment A, Part A.
b. “Dual Purpose Meter” or “Dual Purpose Measuring Station” shall mean any meter or measuring station which is not a Town Border Station or Town Border Measuring Station and which facilitates service to individual customers of the Buyer. “Dual Purpose Meter” or “Dual Purpose Measuring Station” shall include meters of tap customers and meters of customers downstream of unmeasured delivery points. “Dual Purpose Meters” or “Dual Purpose Measuring Stations” shall be listed on Attachment A, Part B.

2.18 "MMBtu" shall mean one million British Thermal Units.

2.19 "Month" shall mean the period beginning on the first Day of the calendar Month and ending on the first Day of the next calendar Month.

2.20 "Total Heating Value" shall mean the gross heating value on a wet basis, which is the number of BTUs produced by the complete combustion of one Cubic Foot of Gas, with combustion air at the same temperature and pressure as the Gas, the products of combustion being cooled to the initial temperature of the Gas and air, and the water formed by combustion condensed to the liquid state.

ARTICLE III -- SERVICE TO BE RENDERED

3.1 Character and Availability of Service. Seller hereby agrees to sell and deliver on a firm basis to Buyer the quantities of Gas set forth in Section 4.1 herein. In addition, should Buyer wish to add a new customer to Seller's Gathering Facilities, and should Seller approve the additional tap pursuant to Article 4.2, Seller shall be responsible for providing the tap and first valve at a cost not to exceed $400.00 per tap. In those instances where the cost exceeds $400.00 per tap, Seller shall provide Buyer the opportunity to contribute the amount in excess of $400.00 to add the new customer.

3.2 Seller's Responsibility for Abandonment. Buyer acknowledges that Seller is a producer and gatherer of Gas and, because Gas is a depletable natural resource, Seller reserves the right to take out of service all or any portion of its Gathering Facilities based upon its needs, or when the necessary supply of Gas is depleted. Seller acknowledges that Buyer may have certain public utility service obligations to Buyer's Customers that may require regulatory approval to terminate. Therefore, Seller agrees to notify Buyer in advance if and when Seller decides to remove any particular Facilities from service that would affect the delivery of Gas to one or more Meters subject to this Contract. Further, Seller agrees that it shall not reduce or terminate service to Buyer by removing such Gathering Facilities from service unless and until: (a) Buyer determines that the affected Buyer's Customer(s) can be served through means other than Seller's service pursuant to this Contract, and Buyer, in its sole discretion, determines that such other means of service will provide economic, adequate, and reliable service to the affected Buyer's customer(s); or (b) Buyer informs Seller in writing that it is able to terminate Gas service to the affected Buyer's Customer(s) based upon a contractual agreement with the Customer(s) providing for cessation of the service under circumstances that include lack of supply, and Buyer receives regulatory approval for such termination; or (c) Buyer is required to and does obtain regulatory approval to abandon the affected Buyer's Customer(s). Buyer agrees to cooperate with and facilitate Seller's decision to remove facilities from service. Attachment A shall be amended promptly to reflect the deletion of each of Buyer's Customer(s) abandoned pursuant to this Section 3.2.

3.3 Right of First Refusal. If Seller proposes to remove from service, pursuant to Section 3.2 above, any of the Gathering Facilities which serve a Town Border Station, Seller shall give Buyer the right to purchase such Gathering Facilities from Seller at fair market value on an "as is" basis before Seller seeks any other purchaser for such Gathering Facilities.

3.4 Failure to Perform. Notwithstanding anything herein to the contrary, and in addition to all other remedies under contract and at law, in the event Seller fails to meet its obligations pursuant to this Contract for any reason except Force Majeure as defined in Article XII, Seller shall pay Buyer any monetary loss experienced upon the commercially reasonable purchase of replacement services and all consequential damages that Buyer experiences upon Seller's failure to meet its obligations.

3.5 Except as specifically provided for in this Agreement, nothing herein shall be construed as making Seller responsible for any other cost or obligation associated with Buyer providing service to its customers served from Sellers Gathering Facilities.

ARTICLE IV – QUANTITIES

4.1 Seller agrees to sell to Buyer quantities of Gas up to the total of the Maximum Daily Quantities as established for each Delivery Point and listed on Attachment A as amended and updated from time to time. Demand by Buyer for quantities in excess of the total of the Maximum Daily Quantities shall be met by Seller through the Gathering Facilities on a best efforts basis, and shall be delivered pursuant to the terms of this Contract except for the difference between the reliability of service in relation to best efforts basis and firm basis.

4.2 If Buyer proposes to add new customers for service on the Gathering Facilities, Buyer shall notify Seller for the purpose of assuring that the addition of such customer(s) will not adversely affect reliability of service to Buyer's existing customers and for the purpose of determining whether adequate gas supplies are available upstream from the proposed point of delivery. Attachment A shall be amended promptly to reflect the addition of each additional Buyer's Customer, provided service to the new customer is approved by Seller. Unless otherwise agreed to by both parties, Buyer and Seller agree to utilize existing taps on Seller's Gathering Facilities to provide service to new customers if the tap for the new customer would otherwise be made within two-hundred (200) feet of any existing tap; provided, however, that new taps would be made within 200 feet of any existing tap if physical circumstances make the utilization of the existing tap impractical.

ARTICLE V -- TERM

5.1 This Agreement will become effective on November 1, 1999 and will remain in full force and effect for a primary term of five (5) years until October 31, 2004.

5.2 Upon the expiration of the primary term of this Contract , this Agreement will be automatically renewed each year for an additional one (1) year term, unless either party hereto has submitted written notice of termination at least six (6) months prior to the expiration date of the then-current term. Any termination by Seller is expressly subject to the abandonment provisions of Section 3.2, above.

ARTICLE VI -- PRICE

6.1 For each Dth of Gas sold and delivered hereunder, Buyer agrees to pay Seller the Contract Price. The Contract Price shall equal 100% of the Agreed Index Price plus $0.75/Dth.

6.2 The total charge paid by Buyer to Seller each month will equal the Contract Price multiplied by the quantity of Gas (Dth) delivered during the Billing Cycle by Seller to Buyer at the Points of Delivery.

6.3 In the event that the Agreed Index of this agreement should cease to be published, Seller and Buyer shall select a replacement index by mutual agreement. If Seller and Buyer are unable to agree on a replacement index, each party shall select a replacement from among the following indices: (a) *Natural Gas Intelligence, Gas Price Index*, Average Spot Gas Price for 30-Day Supply Transactions delivered into Columbia Gas -- Appalachia; (b) *Natural Gas Week*, Gas Price Report for Spot Prices delivered into Columbia Gas Transmission Corp. - Appalachian Pooled, under the subheading "Bid Week for (Month)." Such designation shall be provided in writing to the other party within 30 days of the last publication of the original Agreed Index. The commodity charge each month shall be determined using the mutually agreed upon index or the average of the two replacement indices designated by the parties as substitutes for the original Agreed Index. If all the replacement indices should cease to be published, the parties will attempt to select a replacement index by mutual agreement. If Seller and Buyer are unable to agree upon a replacement index, the selection of replacement index shall be resolved pursuant to the dispute resolution procedures set forth in Article XIV herein.

ARTICLE VII-- QUALITY

7.1 The parties recognize that the Gas used to provide service from the Gathering Facilities is raw, unprocessed gas. Seller shall not be required to process or treat the Gas prior to its delivery to Buyer.

ARTICLE VIII -- MEASUREMENT

8.1 The measurement unit shall be one Dth of Gas and shall be calculated by multiplying the volume delivered in Mcf by a fraction, the numerator of which is the Total Heating Value and the denominator of which is one thousand (1,000).

8.2 The volumetric measurement base shall be one Cubic Foot of Gas.

8.3 The Btu value per Cubic Foot which shall be used in calculating the quantity of Gas delivered by Seller to Buyer at each Point of Delivery shall be 1.2 MMBtu / Mcf.

8.4 All Gas delivered by Seller to Buyer shall be measured at the Delivery Point(s) by an orifice, turbine or displacement type Meter or other approved measuring device of equal accuracy to be installed and operated by Buyer, except as hereinafter provided.

8.5 Where the delivery of Gas to Buyer is unmeasured at the interconnection of Seller's Gathering Facilities and Buyer's facilities, Seller may install test measurement equipment. Should quantities determined by test measurement differ from quantities measured further downstream by Buyer by two percent or more, Buyer, within 30 days of notification of such difference, at its option may correct the cause of such difference by bringing the measurement within a two percent tolerance, by installing new measurement equipment at the said interconnection, or by any other mutually agreeable method at its sole expense. Should said quantities differ by less than two percent, Seller, at its option, may elect to install new measurement equipment at the interconnection of Seller's and Buyer's facilities at Seller's sole expense. New measurement installed by either Seller or Buyer at the interconnection of Seller's and Buyer's facilities shall be recognized as the new Delivery Point on Attachment A.

8.6 For orifice Meter measurements, the methods of computation shall conform with the recommendations of the American Gas Association Measurement Committee Report No. 3, (April, 1955) including the Appendix thereto, as amended from time to time, applied in a practical manner.

8.7 For displacement or turbine Meters or other approved measuring device, the Meter readings at various pressures shall be converted to Gas quantities at the base conditions of a Gas temperature of sixty degrees (60°) Fahrenheit when saturated with water vapor and at a pressure of 14.73 psia.

8.8 In connection with the use of any type measuring device an average atmospheric pressure of fourteen and four tenths (14.4) psia shall be assumed, with no allowance for variation in atmospheric pressure. The flowing Gas temperature may be recorded, at the Buyer's discretion. In the absence of a flowing Gas temperature recorder, sixty degrees (60°) Fahrenheit will be assumed.

8.9 The Buyer shall own, operate, maintain, test, repair and read all Meter(s) used to provide service under this Agreement and shall provide to Seller the volumes measured for billing purposes. If, upon any tests, any Meter is found to be in error, and the resultant aggregate error in computed deliveries at the recording rate corresponding to the average hourly rate of Gas flow for the period since the preceding test is not more than two percent (2%), then previous deliveries shall be considered accurate, and no adjustment made. If, however, any such Meter is found to be in error, and the resultant aggregate error in computed deliveries exceeds two percent (2%) at the recording rate corresponding to the average hourly rate of Gas flow for the period since the preceding test, then the previous recordings of such equipment shall be corrected to zero error, and the computed deliveries and billings shall be adjusted by Buyer. The adjustment shall not cover a period which is longer than 2 years. All equipment shall, in any case, be adjusted at the time of test to record correctly. To the extent errors, as calculated above, result in retroactive adjustments to the deliveries to Buyer's Customers served from the Meter(s), then those adjustments shall be made to the deliveries from Seller to Buyer.

8.10 If Seller challenges the accuracy of any Meter(s) operated by Buyer in use under this Contract and requests to have the Meter tested, the Meter operator shall test the Meter in the presence of Seller if Seller wishes to be present or to be represented at such test. If the Meter upon test proves to be accurate within plus or minus two percent (2%), the cost of testing and repairing the Meter shall be borne by Seller, but if the Meter on test proves to be in error by more than two percent (2%), the cost of testing and repairing the same shall be borne by Buyer. Any resultant aggregate error exceeding two percent (2%) of computed sales and delivery shall be adjusted pursuant to Sections 9.8 and 9.9 of this Contract.

8.11 Buyer shall notify Seller 30 days prior to any routine field maintenance and/or field tests of its Meters, and shall allow Seller or its representative to be present at such tests.

8.12 If any Meter is out of service for test or repair, or is inoperable for any reason, Gas deliveries through such equipment shall be estimated by Buyer utilizing all available information to determine the volume of Gas for the sales and delivery period affected.

8.13 Upon written request from Seller, Buyer shall forward copies of Meter charts to Seller. Buyer shall keep the original Meter charts on file for two (2) years after the date of delivery, during which time they will be open for inspection by Seller.

8.14 Considering the possibility of inadvertent errors in measurement or calculation of amounts due and payable or paid, nothing herein contained shall constitute accord and satisfaction, waiver, release, full payment, satisfaction, laches, estoppel or other defense to a claim by or against the Seller or Buyer for the true and actual amount accurately due and payable for the full period of two (2) years in arrears. Errors in Buyer's favor shall be rectified in full, without interest, by Buyer within ninety (90) days of notice and substantiation of such inaccuracy. Errors in Seller's favor shall be rectified in full, without interest, by Seller within ninety (90) days of notice and substantiation of such inaccuracy or, at Buyer's option, such error may be rectified by Buyer withholding one hundred percent of payments accruing to Seller, or its benefit, under this Contract until the error is corrected in full.

8.15 As Attachment A is updated and as customers are added to or deleted from Attachment A, the parties will mutually agree on the appropriate MDQ change, if necessary. If Attachment A is found to have been incorrect for any previous month, then the parties will mutually agree on the retroactive payment or refund that will be required.

ARTICLE IX -- TAXES

9.1 Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all taxes on or with respect to the Gas at or after its delivery at the Delivery Point(s). If a party is required to remit or pay Taxes which are the other party's responsibility hereunder, such party shall promptly reimburse the other party for such Taxes.

9.2 Neither the price to be paid for sales and delivery service nor any other provision of this Agreement shall be affected by an increase or decrease in the rate or amount of any tax or the repeal of an existing tax imposed on either party, by the enactment of a new tax, or by the subsequent application hereto of any existing tax.

ARTICLE X -- BILLING, PAYMENT AND AUDIT

10.1 Buyer agrees to provide to Seller the quantities of gas, in Mcf, delivered by Seller for each Billing Cycle on or before the tenth (10^{th}) day of the month following the meter reading and/or chart calculations for such period. Seller shall remit to Buyer an invoice based on the volumes provided by Buyer. Buyer shall remit payment to Seller within 10 days of receiving the invoice from Seller. Checks, payable to the order of Seller, shall be mailed to Seller at the address specified in Article XV herein.

10.2 Although the terms of this Contract extend to and are binding upon all parties to it, their respective successors, assigns, personal representatives, and heirs, in no event will Buyer issue, or be required to issue, more than one (1) monthly check in payment of the amounts due hereunder.

10.3 If, at any time, more than one (1) person, party, or entity shall claim or become entitled to payment for the amounts due hereunder, Buyer may withhold such payment, without interest, until Seller furnishes Buyer with the necessary documentation, properly executed and acknowledged by all necessary parties, designating an agent to receive such payment or until such time as the controversy is satisfactorily resolved.

10.4 Each Party shall have the right, upon reasonable notice and at reasonable times, to examine the books and records of the other party to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, computation or other documentation made under the Contract. Any such audit and any claim based upon errors must be made within two years of the date of such statement or any revision thereof. Following such two year period, a billing statement shall be deemed final. Errors in a party's favor shall be rectified in full by the other party within 30 Days of notice and substantiation of such inaccuracy.

10.5 The receipt of any invoice, statement or information concerning a transaction or the act of payment or partial payment shall not constitute accord and satisfaction, waiver, release, full payment, satisfaction, laches, estoppel or other defense to a claim by or against the Seller or Buyer for the true and actual amount accurately due and payable for the full period of two years in arrears.

ARTICLE XI -- TITLE, WARRANTY AND INDEMNITY

11.1 Seller warrants that at the time of sale and delivery it will have the right to sell and deliver the Gas sold hereunder and that it will indemnify Buyer and save it harmless from suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of adverse claims of any and all persons to such Gas, and royalties, taxes, license fees or charges on such Gas, to the extent that they arise or attach prior to delivery at the Points of Delivery.

11.2 Seller shall be deemed to have title and to be in exclusive control and possession of the Gas delivered hereunder and shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Point(s) of Delivery. Buyer shall be deemed to have title and to be in exclusive control and possession of the Gas and shall have responsibility for and any liability with respect to said Gas after its delivery to Buyer at the Point(s) of Delivery.

11.3 Seller and Buyer each warrants that it is engaged in the direct commercial use of natural Gas in the ordinary course of its business, as producer, processor, merchant, or consumer or otherwise has knowledge of the practices associated with the purchase or sale of natural Gas. Each further warrants that it has and will maintain all the regulatory authorizations, certificates, and documentation as may be necessary and legally required to transport, buy, or make sales for resale of Gas sold or purchased hereunder.

11.4 If any claim related to the title to the Gas delivered hereunder is asserted at any time, Buyer may withhold payment of up to the amount of such claim without interest, as security for the performance of Seller's obligations hereunder until such claim has been finally determined, or until Seller has furnished a bond or other acceptable assurances to Buyer under terms and conditions satisfactory to Buyer, and in an amount with surety satisfactory to Buyer.

11.5 Seller agrees to indemnify Buyer and save it harmless from all suits, actions, debts, accounts, damages, costs, losses, liabilities and expenses arising from or out of claims of title, personal injury or property damage from any or all persons to said Gas or other charges thereon which attach before delivery to Buyer. Buyer agrees to indemnify Seller and save it harmless from all suits, actions, debts, accounts, damages, costs, losses, liabilities and expenses arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach at and after title passes to Buyer, subject to Seller's obligations enumerated specifically herein.

ARTICLE XII -- FORCE MAJEURE

12.1 Except with regard to a party's obligation to make payments due under the Contract, neither party shall be liable to the other for a failure to perform its obligations hereunder, if such failure was caused by Force Majeure. As used herein, the term "Force Majeure" shall mean an unforeseen occurrence or event beyond the control of the party claiming excuse which partially or entirely prevents that party's performance of its obligations, except the obligation to make payments due under any transaction.

12.2 The party whose performance is prevented by Force Majeure must provide notice to the other party. Initial notice may be given orally; however, written notification with particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written notification of Force Majeure to the other party, the affected party will be relieved of its obligation to make/accept sales and deliveries of Gas to the extent and for the duration of Force Majeure and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

12.3 Force Majeure shall include but not be limited to the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe, weather - related events such as hurricanes or freezing or failure of wells or lines of pipe which affects an entire geographic region; (ii) acts of others such as strikes, lockouts, or other industrial disturbances, riots, sabotage, insurrections or wars; (iii) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction; and (iv) any other causes, whether of the kind herein enumerated or otherwise not reasonably within the control of the affected party. Seller and Buyer shall make reasonable efforts to avoid Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

12.4 Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected from any or all of the following circumstances: (i) the sole or contributory negligence of the party claiming excuse; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; (iii) economic hardship. As soon as possible after the Force Majeure event shall have been remedied, the party claiming suspension shall likewise give notice to the effect that the same has been remedied and that such party has resumed, or is then in a position to resume, the performance of such covenants or obligations.

12.5 Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be entirely within the discretion of the party experiencing such disturbance.

ARTICLE XIII -- GOVERNMENTAL REGULATION

13.1 This Contract and all provisions herein will be subject to all present and future applicable and valid statutes, rules, orders and regulations of any Federal, State, or local governmental authority having jurisdiction over the parties, their facilities or Gas supply, this Contract or any provisions thereof.

13.2 Each party certifies that, during the performance of this Contract, its employment practices, pertaining to employees and applicants, shall comply with all federal, state and local laws and regulations regarding discrimination because of race, color, religion, national origin, sex, age, disability or veteran status, including but not limited to the provisions of the Civil Rights Act of 1964, Fair Labor Standards Act of 1938, Americans with Disabilities Act of 1990, Executive Order 11246 of September 24, 1965, Family and Medical Leave Act of 1993, Code of Federal Regulations (CFR); 41 CFR Part 60-1, 41 CFR Part 60-250, and 41 CFR Part 60-741, all provisions as amended, and all provisions thereof being incorporated herein by reference.

13.3 Neither party will be held in default for failure to perform under this Contract, if such failure is due to compliance with the rules, regulations, laws, orders or directives of any State, Federal or other governmental regulatory authority having jurisdiction over the party.

13.4 Notwithstanding any other provision of this Agreement, if any applicable law, or any order, opinion, enactment of regulation of the FERC, the Public Service Commission of Kentucky, or of any other governmental authority (Federal or State) or of any court, may have the effect, either directly or as a precedent, of preventing Buyer's full recovery of any portion of the purchase price paid or to be paid to Seller hereunder, then Buyer, beginning in the next monthly billing cycle after the effective date of such law, order, opinion, enactment or regulation, or at such later date as Buyer may elect, may reduce the purchase price which Buyer is obligated to pay to Seller hereunder to that price level which will enable Buyer to have such full recovery. In such case, at Seller's option, the price provisions applicable to Seller's deliveries of gas to Buyer hereunder shall be deemed modified as appropriate so that Buyer will have such full recovery or Buyer and Seller shall negotiate a transportation arrangement for the delivery of gas to Buyer at a rate sufficient to compensate Seller for the service being provided under the terms of this Agreement. Seller shall not, however, be liable to Buyer for any overpayment hereunder prior to the effective date of such law, order, opinion, enactment or regulation. Buyer shall use its best efforts to prevent the enactment or promulgation of any such order, opinion, enactment or regulation.

ARTICLE XIV -- DISPUTE RESOLUTION

14.1 In the event a dispute arises between Buyer and Seller, or the successors or assigns of either of them, regarding the application or interpretation of any provision of this Contract, either party may promptly notify the other party to this Contract of its intent to invoke this dispute resolution procedure. If the parties shall have failed to resolve the dispute within ten (10) days after delivery of such notice, each party shall, within five (5) days thereafter nominate a senior officer of its management to meet at Buyer's offices or any other mutually agreed location to resolve the dispute. Should the parties be unable to resolve the dispute to their mutual satisfaction within ten (10) days after such nomination, such dispute shall be settled by arbitration.

14.2 The party desiring arbitration shall give notice to the other party in writing specifying the question or questions to be settled and at the same time naming an arbitrator. The party receiving such notice shall within ten (10) days thereafter give to the other party a like written notice giving the name of an arbitrator chosen by it and specifying any additional matter on which an award is desired. If the party receiving notice of arbitration fails to name an arbitrator within ten (10) days, then the second arbitrator shall be appointed by the American Arbitration Association. Only parties certified as arbitrators with the American Arbitration Association will be appointed as arbitrators. A third arbitrator shall, within ten (10) days of the appointment of the second arbitrator, be selected by the two arbitrators theretofore appointed. If arbitrators shall have been appointed by the respective parties and shall have failed to select the third arbitrator within the time provided herein, the third arbitrator shall, upon application of either of the parties to the arbitration, be appointed by the American Arbitration Association within ten (10) days after receipt of a party's application to appoint a third arbitrator. The arbitrators shall proceed immediately to hear and determine the matter in controversy. Each party shall be entitled to produce witnesses and appear in person and by counsel before said arbitrators, but the number of witnesses to be heard, the length of argument, the time consumed in such hearing, and the general conduct of the proceedings shall conform to the rules promulgated by the American Arbitration Association. The arbitrators shall be limited to accepting the position contended for by either the Seller or the Buyer, without modification, in making their award. The arbitrators shall be instructed that their award must be made within forty-five (45) days of the appointment of the third arbitrator, subject to any reasonable delay due to unforeseen circumstances. The award of the arbitrators shall be drawn up in writing and signed by the arbitrators, or a majority of them, and shall be final and binding on the parties, and the parties shall abide by the award and perform the terms and conditions thereof. The award of the arbitrators shall be made retroactive to the date the first party notified the other party of its intent to invoke the dispute resolution procedure. Unless otherwise determined by the arbitrators, the fees and expenses of the arbitrator named by Seller shall be paid by Seller, the fees and expenses of the arbitrator named by Buyer shall be paid by Buyer and the fees and expenses of the third arbitrator shall be paid in equal proportions by the Buyer and Seller. Save as herein otherwise expressly provided, the rules of the American Arbitration Association shall apply, and wherever and whenever there is conflict between the provisions of this Article and the provisions of the said rules, the provisions of this Article shall apply. In no event shall the arbitration panel have the authority to award consequential, incidental, or punitive damages to either party.

ARTICLE XV -- NOTICES

15.1 All communications ("Communications") made pursuant to the Agreement shall be sent or hand delivered to the Buyer at the address shown below:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY 40391
Attn: George S. Billings
Phone: (606) 744-6171
Fax: (606) 744-3623

15.2 All notices and payments shall be sent or hand delivered to the Seller at the address shown below:

<u>Notices to:</u>
Columbia Natural Resources, Inc.
900 Pennsylvania Avenue, P.O. Box 6070
Charleston, WV 25362-0070
Attn: Manager, Gas Supply
Phone: 304-353-5151
Fax: 304-353-5155

<u>Payments to:</u>
Columbia Natural Resources, Inc.
P.O. Box 640793
Pittsburgh, PA 15264-0793

15.3 Either party may modify any information specified above by written notice to the other party.

15.4 All Communications and payments ("Notices") required hereunder may be sent by telecopier or generally accepted electronic means, a nationally recognized overnight courier service, first class mail or hand delivered. All invoices required hereunder may be sent by first class mail.

ARTICLE XVI -- MISCELLANEOUS

16.1 This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party, which consent will not be unreasonably withheld.

16.2 If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

16.3 No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach. All remedies afforded in this Contract shall be taken and construed as cumulative.

16.4 This Contract sets forth all understandings between the parties respecting the subject matter of each transaction and any prior Contract, understandings and representations, whether oral or written, representing this subject matter are merged into and superseded by the Contract. This Contract may only be amended in writing.

16.5 This Contract may be executed in one or more counterparts, each of which shall be deemed an original, and all of which together shall constitute one and the same instrument. As used herein, the singular of any term shall include the plural.

16.6 The interpretation and performance of this Contract shall be governed by the laws of the Commonwealth of Kentucky, excluding, however, any conflict of laws rule which would apply to the law of another jurisdiction.

16.7 This Contract was prepared jointly by Seller and Buyer, and, in the event of doubt or ambiguity in the language of any of its provisions, shall be construed with equal strength in favor of both parties.

16.8 All lines, valves and fittings furnished under this Agreement shall remain the property of the party furnishing same and may be removed by such party at the termination of this Agreement. Buyer shall have the right to operate Seller's valves located at the intersection of Buyer's and Seller's facilities, when necessary, to remove, repair, or replace Buyer's facilities.

IN WITNESS WHEREOF, this Contract has been properly executed by the parties hereto as of the date first above written.

ATTEST:
DELTA NATURAL GAS COMPANY, INC.

by: Amy S. Bieeing

title: Mgr - Gas Supply

date: 10-28-99

COLUMBIA NATURAL RESOURCES, INC.

by: [signature]

title: VICE PRESIDENT

date: October 27 1999

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: July 21, 2016

The parties to this Base Contract are the following:

PARTY A		PARTY B
GREYSTONE, LLC	PARTY NAME	DELTA NATURAL GAS COMPANY, INC.
600 The Grange Lane Lexington, KY 40511	ADDRESS	3617 Lexington Road Winchester, KY 40391
	BUSINESS WEBSITE	
	CONTRACT NUMBER	
	D-U-N-S® NUMBER	
x US FEDERAL: 46-2836520 ☐ OTHER:	TAX ID NUMBERS	☐ US FEDERAL: 61-1103681 ☐ OTHER:
CFTC Interim Compliance Identifier (CICI Number):		CFTC Interim Compliance Identifier (CICI Number):
Kentucky	JURISDICTION OF ORGANIZATION	
☐ Corporation x LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other:	COMPANY TYPE	x Corporation ☐ LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other:
	GUARANTOR (IF APPLICABLE)	
CONTACT INFORMATION		
Same as above ATTN: David Rudder TEL#: (859) 321-1500 FAX#: EMAIL: david@northamericanenergy.com	▪ COMMERCIAL	Same as above ATTN: Brian Ramsey TEL#: (859) 744-6171 FAX#: (859) 744-3623 EMAIL: BRAMSEY@DeltaGas.com
Same as above ATTN: Gas Scheduling TEL#: (859) 321-1500 FAX#: EMAIL:	▪ SCHEDULING	Same as above ATTN: Wayne T. Hunter II TEL#: (859) 744-6171 FAX#: (859) 7443623 EMAIL: WHUNTER@DeltaGas.com
Same as above ATTN: Contract Administration TEL#: (859) 321-1500 FAX#: EMAIL: david@northamericanenergy.com	▪ CONTRACT AND LEGAL NOTICES	Same as above ATTN: TEL#: FAX#: EMAIL:
Same as above ATTN: TEL#: (859) 321-1500 FAX#: EMAIL:	▪ CREDIT	ATTN: TEL#: FAX#: EMAIL:
Same as above ATTN: Confirmation Department TEL#: (859) 321-1500 FAX#: EMAIL: david@northamericanenergy.com	▪ TRANSACTION CONFIRMATIONS	Same as above ATTN: TEL#: FAX#: EMAIL:
ACCOUNTING INFORMATION		
Same as above ATTN: Gas Accounting TEL#: (859) 321-1500 FAX#: EMAIL: david@northamericanenergy.com	▪ INVOICES ▪ PAYMENTS ▪ SETTLEMENTS	Same as above ATTN: TEL#: FAX#: EMAIL:
BANK: Fifth Third Bank, ABA: 042101190 ACCT: 7381091169 OTHER DETAILS:	WIRE TRANSFER NUMBERS (IF APPLICABLE)	BANK: Branch Banking & Trust ABA: 042174486 ACCT: 5182747434 OTHER DETAILS:
BANK: ABA: ACCT: OTHER DETAILS:	ACH NUMBERS (IF APPLICABLE)	BANK: ABA: ACCT: OTHER DETAILS:
ATTN: ADDRESS:	CHECKS (IF APPLICABLE)	ATTN: ADDRESS:

Base Contract for Sale and Purchase of Natural Gas

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select the appropriate box(es) from each section:

Section 1.2 Transaction Procedure
x Oral (default)
OR
☐ Written

Section 2.7 Confirm Deadline
x 2 Business Days after receipt (default)
OR
☐ _____ Business Days after receipt

Section 2.8 Confirming Party
☐ Seller (default)
OR
X Buyer
☐ ______________________

Section 3.2 Performance Obligation
x Cover Standard (default)
OR
☐ Spot Price Standard

Note: The following Spot Price Publication applies to both of the immediately preceding.

Section 2.31 Spot Price Publication
x Gas Daily Midpoint (default)
OR
☐ ______________________

Section 6 Taxes
x Buyer Pays At and After Delivery Point (default)
OR
☐ Seller Pays Before and At Delivery Point

Section 7.2 Payment Date
x 25th Day of Month following Month of delivery (default)
OR
☐ Day of Month following Month of delivery

Section 7.2 Method of Payment
x Wire transfer (default)
☐ Automated Clearinghouse Credit (ACH)
☐ Check

Section 7.7 Netting
x Netting applies (default)
OR
☐ Netting does not apply

Section 10.2 Additional Events of Default
X No Additional Events of Default (default)
☐ Indebtedness Cross Default
☐ Party A: 3% of Shareholder's equity
☐ Party B: 3% of Shareholder's equity

For the purposes of this definition, "Shareholder's Equity" means, at any time, the amount of paid-in capital in respect of all issued and fully-paid shares of the share capital of the relevant entity, together with the contributed surplus, the cumulative translation adjustment (if any) and the retained earnings calculated in accordance with generally accepted accounting principles in the country in which that entity is organized, consistently applied.

☐ Transactional Cross Default
Specified Transactions:

Section 10.3.1 Early Termination Damages
x Early Termination Damages Apply (default)
OR
☐ Early Termination Damages Do Not Apply

Section 10.3.2 Other Agreement Setoffs
x Other Agreement Setoffs Apply (default)
x Bilateral (default)
☐ Triangular
OR
☐ Other Agreement Setoffs Do Not Apply

Section 15.5 Choice Of Law
Kentucky

Section 15.10 Confidentiality
x Confidentiality applies (default)
OR
☐ Confidentiality does not apply

x Special Provisions Number of sheets attached: 4
☐ **Addendum(s):** ______________________

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

GREYSTONE, LLC	PARTY NAME	DELTA NATURAL GAS COMPANY, INC.
By: [signature]	SIGNATURE	By: [signature]
DAVID RUDDER	PRINTED NAME	Brian Ramsey
PRESIDENT	TITLE	VP - Transmission + Gas Supply

General Terms and Conditions
Base Contract for Sale and Purchase of Natural Gas

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.9.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract.

SECTION 2. DEFINITIONS

The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.1. "Additional Event of Default" shall mean Transactional Cross Default or Indebtedness Cross Default, each as and if selected by the parties pursuant to the Base Contract.

2.2. "Affiliate" shall mean, in relation to any person, any entity controlled, directly or indirectly, by the person, any entity that controls, directly or indirectly, the person or any entity directly or indirectly under common control with the person. For this purpose, "control" of any entity or person means ownership of at least 50 percent of the voting power of the entity or person.

2.3. "Alternative Damages" shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.4. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.5. "British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

2.6. "Business Day(s)" shall mean Monday through Friday, excluding Federal Banking Holidays for transactions in the U.S.

2.7. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.8. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.9. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation, all of which shall form a single integrated agreement between the parties.

2.10. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.11. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.12. "Cover Standard", as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.13. "Credit Support Obligation(s)" shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as cash, an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, guaranty, or other good and sufficient security of a continuing nature.

2.14. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.

2.15. "Delivery Period" shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.16. "Delivery Point(s)" shall mean such point(s) as are agreed to by the parties in a transaction.

2.17. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.18. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm", provided that a party's excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.19. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.20. "Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.21. "Guarantor" shall mean any entity that has provided a guaranty of the obligations of a party hereunder.

2.22. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

2.23. "Indebtedness Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it or its Guarantor, if any, experiences a default, or similar condition or event however therein defined, under one or more agreements or instruments, individually or collectively, relating to indebtedness (such indebtedness to include any obligation whether present or future, contingent or otherwise, as principal or surety or otherwise) for the payment or repayment of borrowed money in an aggregate amount greater than the threshold specified in the Base Contract with respect to such party or its Guarantor, if any, which results in such indebtedness becoming immediately due and payable.

2.24. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.25. "MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

2.26. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.27. "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.28. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.29. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.30. "Specified Transaction(s)" shall mean any other transaction or agreement between the parties for the purchase, sale or exchange of physical Gas, and any other transaction or agreement identified as a Specified Transaction under the Base Contract.

2.31. "Spot Price " as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.32. "Transaction Confirmation" shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.33. "Transactional Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it shall be in default, however therein defined, under any Specified Transaction.

2.34. "Termination Option" shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.35. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the "Cover Standard" or the "Spot Price Standard" as indicated on the Base Contract.

Cover Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s) excluding any quantity for which no replacement is available; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s) excluding any quantity for which no sale is available; and (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available for all or any portion of the Contract Quantity of Gas, then in addition to (i) or (ii) above, as applicable, the sole and exclusive remedy of the performing party with respect to the Gas not replaced or sold shall be an amount equal to any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the quantity of such Gas not replaced or sold. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

Spot Price Standard:
3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.
Buyer Pays At and After Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.
Seller Pays Before and At Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed without undue delay. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 15.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury (including death) or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. The parties agree that the delivery of and the transfer of title to all Gas under this Contract shall take place within the Customs Territory of the United States (as defined in general note 2 of the Harmonized Tariff Schedule of the United States 19 U.S.C. §1202, General Notes, page 3); provided, however, that in the event Seller took title to the Gas outside the Customs Territory of the United States, Seller represents and warrants that it is the importer of record for all Gas entered and delivered into the United States, and shall be responsible for entry and entry summary filings as well as the payment of duties, taxes and fees, if any, and all applicable record keeping requirements.

8.5. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payment instructions, and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder shall be in writing and may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

9.4. The party receiving a commercially acceptable Notice of change in payment instructions or other payment information shall not be obligated to implement such change until ten Business Days after receipt of such Notice.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party ("X") has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party ("Y") (including, without limitation, the occurrence of a material change in the creditworthiness of Y or its Guarantor, if applicable), X may demand Adequate Assurance of Performance. "Adequate Assurance of Performance" shall mean sufficient security in the form, amount, for a term, and from an issuer, all as reasonably acceptable to X, including, but not limited to cash, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or guaranty. Y hereby grants to X a continuing first priority security interest in, lien on, and right of setoff against all Adequate Assurance of Performance in the form of cash transferred by Y to X pursuant to this Section 10.1. Upon the return by X to Y of such Adequate Assurance of Performance, the security interest and lien granted hereunder on that Adequate Assurance of Performance shall be released automatically and, to the extent possible, without any further action by either party.

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its Guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; or ix) be the affected party with respect to any Additional Event of Default; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is legally permissible, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.

Early Termination Damages Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions).

For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and

Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.

Early Termination Damages Do Not Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract.

The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.

Other Agreement Setoffs Apply:

Bilateral Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff any Net Settlement Amount against (i) any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; and (ii) any amount(s) (including any excess cash margin or excess cash collateral) owed or held by the party that is entitled to the Net Settlement Amount under any other agreement or arrangement between the parties.

Triangular Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option, and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff (i) any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; (ii) any Net Settlement Amount against any amount(s) (including any excess cash margin or excess cash collateral) owed by or to a party under any other agreement or arrangement between the parties; (iii) any Net Settlement Amount owed to the Non-Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Non-Defaulting Party or its Affiliates to the Defaulting Party under any other agreement or arrangement; (iv) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party to the Non-Defaulting Party or its Affiliates under any other agreement or arrangement; and/or (v) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party or its Affiliates to the Non-Defaulting Party under any other agreement or arrangement.

Other Agreement Setoffs Do Not Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of the Net Settlement Amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount as well as any setoffs applied against such amount pursuant to Section 10.3.2, shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount as adjusted by setoffs, shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Contract; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6, Section 10, Section 13, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 14. MARKET DISRUPTION

If a Market Disruption Event has occurred then the parties shall negotiate in good faith to agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each party obtaining, in good faith and from non-affiliated market participants in the relevant market, two quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point and averaging the four quotes. If either party fails to provide two quotes then the average of the other party's two quotes shall determine the replacement price for the Floating Price. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) both parties agree that a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

SECTION 15. MISCELLANEOUS

15.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or Affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

15.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

15.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

15.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

15.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

15.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

15.7. There is no third party beneficiary to this Contract.

15.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

15.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

15.10. Unless the parties have elected on the Base Contract not to make this Section 15.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract , (iii) to the extent necessary to implement any transaction, (iv) to the extent necessary to comply with a regulatory agency's reporting requirements including but not limited to gas cost recovery proceedings; or (v) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure, and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

15.11. The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties

15.12. Any original executed Base Contract, Transaction Confirmation or other related document may be digitally copied, photocopied, or stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the Transaction Confirmation, if introduced as evidence in automated facsimile form, the recording, if introduced as evidence in its original form, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings will be admissible as between the parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the recording, the Transaction Confirmation, or the Imaged Agreement on the basis that such were not originated or maintained in documentary form. However, nothing herein shall be construed as a waiver of any other objection to the admissibility of such evidence.

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Letterhead/Logo	Date: ______________________, _____ Transaction Confirmation #: ____________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated ________________. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
____________________	____________________
____________________	____________________
____________________	____________________
Attn: ____________________	Attn: ____________________
Phone: ____________________	Phone: ____________________
Fax: ____________________	Fax: ____________________
Base Contract No. ____________________	Base Contract No. ____________________
Transporter: ____________________	Transporter: ____________________
Transporter Contract Number: ____________	Transporter Contract Number: ____________

Contract Price: $______/MMBtu or ____

Delivery Period: Begin: ___________, ____ End: _________, ____

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
_______ MMBtus/day	_______ MMBtus/day Minimum	Up to ______ MMBtus/day
☐ EFP	_______ MMBtus/day Maximum	
	subject to Section 4.2. at election of	
	☐ Buyer or ☐ Seller	

Delivery Point(s): ________________________
(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions:

Seller: ____________________	Buyer: ____________________
By: ____________________	By: ____________________
Title: ____________________	Title: ____________________
Date: ____________________	Date: ____________________

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

GREYSTONE, LLC

Date: August 30, 2017

Transaction Confirmation #083017DEL

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated July 21, 2016. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

BUYER:	**SELLER:**
Delta Natural Gas Company, Inc.	Greystone, LLC
3617 Lexington Road	600 The Grange Lane
Winchester, KY 40391	Lexington, KY 40511
Attn: Brian Ramsey	Attn: David Rudder
Phone: (859) 744-6171, ext 1158	Phone: (859) 321-1500
Fax: (859) 744-3623	Fax:
Base Contract No.	Base Contract No.
Transporter:	Transporter:
Transporter Contract Number:	Transporter Contract Number:

Contract Price: $______/MMBtu or 100% Monthly NYMEX Settlement Price plus $.10/Mmbtu

Delivery Period: Begin: August 1, 2017 End: July 31, 2018

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):
_______ MMBtus/day
☐ EFP

Firm (Variable Quantity):
_______ MMBtus/day Minimum
_______ MMBtus/day Maximum
subject to Section 4.2. at election of
☐ Buyer or ☐ Seller

Interruptible:
Up to 200 MMBtus/day

Delivery Point(s): Delta/Somerset Meters
(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions:

Buyer: DELTA NATURAL GAS COMPANY, INC.	Seller: GREYSTONE, LLC
By: Brian Ramsey	By: [signature]
Title: VP - Transmission + Gas Supply	Title: Managing Member
Date: 9/11/17	Date: 8/30/17

Exhibit 3-1

DELTA NATURAL GAS COMPANY, INC.
TENNESSEE GAS PIPELINE MAXIMUM DAILY QUANTITIES
VOLUMES SHOWN IN DTH

MONTH	NICHOLASVILLE METER #20248			BEREA METER #20208	J'VILLE METER #20430	SALT LICK, FARMERS-MIDLAND, CLEARFIELD & KINDER METERS #20212, 20462 & 20733	WEST BEND METER #20813	TOTAL MDQ
	FT-G	FT-A	TOTAL	FT-G	FT-G	FT-G	FT-G	
JANUARY	8,561	1,400	9,961	7,500	400	2,000	250	20,111
FEBRUARY	8,561	1,400	9,961	7,500	400	2,000	250	20,111
MARCH	5,600	1,400	7,000	6,500	300	1,500	150	15,450
APRIL	4,000	1,400	5,400	4,000	200	800	75	10,475
MAY	2,800	1,400	4,200	2,500	200	600	50	7,550
JUNE	2,000	1,400	3,400	1,676	150	400	50	5,676
JULY	2,000	1,400	3,400	1,676	150	372	50	5,648
AUGUST	2,000	1,400	3,400	1,676	150	372	50	5,648
SEPTEMBER	2,000	1,400	3,400	1,676	250	400	100	5,826
OCTOBER	3,644	1,400	5,044	3,000	300	800	100	9,244
NOVEMBER	5,000	1,400	6,400	5,800	300	1,800	175	14,475
DECEMBER	8,561	1,400	9,961	7,500	400	2,000	250	20,111

Exhibit 3-2

NICHOLASVILLE
FT-A TRANSPORTATION CONTRACT NO. 2747
RATE SCHEDULE FT-A

SERVICE PACKAGE NUMBER:	2747
SERVICE PACKAGE TQ:	1,400 DTH/DAY
TERM:	NOVEMBER 1, 2014 TO OCTOBER 31, 2019
NUMBER OF RECEIPT POINTS:	11
NUMBER OF DELIVERY POINTS:	1

DELIVERY POINTS

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER-TQ
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	1,400

TSP: 4052 - TENNESSEE GAS PIPELINE AGENT: 6458 - DELTA NAT GAS SVC REQ: 6458 - DELTA NAT GAS

Exhibit 3-3

Contract No.: 2747-FTATGP

Rate Sch: FTA Term Start: 9/1/1993 Term End: 10/31/2019

Eff. From: 8/27/2018 Eff. Thru: 11/1/2018

Eff. From	Eff. Thru	Cycle	Rate Code	Rate Component	Rate	Rate Type
11/01/2018	10/31/2019	ANNUAL	RESV	RESV	10.673500	MAX
05/01/2018	10/31/2019	ANNUAL	RESV	PSGHG	0.021600	MAX
12/01/2016	10/31/2019	ANNUAL	AOR	PSGHG	0.001600	MAX
12/01/2016	10/31/2019	ANNUAL	CMDY	PSGHG	0.000900	MAX
12/01/2016	10/31/2019	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
12/01/2016	10/31/2018	ANNUAL	RESV	RESV	10.898200	MAX

SALT LICK, FARMERS & KINDER-HILDA
FT-G TRANSPORTATION CONTRACT NO. 2448
RATE SCHEDULE FT-G

SERVICE PACKAGE NUMBER: 2448
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019

MONTHLY MDQ JANUARY:	2,000
MONTHLY MDQ FEBRUARY:	2,000
MONTHLY MDQ MARCH:	1,500
MONTHLY MDQ APRIL:	800
MONTHLY MDQ MAY:	600
MONTHLY MDQ JUNE:	400
MONTHLY MDQ JULY:	372
MONTHLY MDQ AUGUST:	372
MONTHLY MDQ SEPTEMBER:	400
MONTHLY MDQ OCTOBER:	800
MONTHLY MDQ NOVEMBER:	1,800
MONTHLY MDQ DECEMBER:	2,000

NUMBER OF RECEIPT POINTS: 12
NUMBER OF DELIVERY POINTS: 3

DELIVERY POINTS

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL01	690
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL02	690
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL03	627
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL04	100
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL05	75
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL06	50
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL07	55
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL08	55
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL09	60
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL10	275
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL11	927
020462	DELTA-SALT LICK KY	DELTA NATURAL GAS CO, INC.	BATH	KY	02	D	087	DQL12	690
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL01	1,260
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL02	1,260
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL03	840
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL04	675
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL05	505
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL06	330
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL07	297
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL08	297
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL09	320
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL10	500
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL11	840
020462	DELTA-FARMERS KY	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL12	1,260
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL01	50
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL02	50
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL03	33
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL04	25
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL05	20
020733	DELTA-KINDER/HILDA SALES	DELTA NATURAL GAS CO, INC.	ROWAN	KY	02	D	087	DQL06	20

TSP: 4052 - TENNESSEE GAS PIPELINE AGENT: 6458 - DELTA NAT GAS SVC REQ: 6458 - DELTA NAT GAS

Exhibit 3-5

Contract No.: 2448-FTGTGP

Rate Sch: Term Start: Term End:

Eff. From: 8/27/2018 Eff. Thru: 11/1/2018

Eff. From	Eff. Thru	Cycle	Rate Code	Rate Component	Rate	Rate Type
11/01/2018	11/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	RESV	12.916100	MAX
10/01/2018	10/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	RESV	12.670600	MAX
09/01/2018	09/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	RESV	12.232700	MAX
08/01/2018	08/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	RESV	12.352500	MAX

Exhibit 3-6

JEFFERSONVILLE
FT-G TRANSPORTATION CONTRACT NO. 2516
RATE SCHEDULE FT-G

SERVICE PACKAGE NUMBER:	2516
TERM:	NOVEMBER 1, 2014 TO OCTOBER 31, 2019

MONTHLY MDQ JANUARY:	400
MONTHLY MDQ FEBRUARY:	400
MONTHLY MDQ MARCH:	300
MONTHLY MDQ APRIL:	200
MONTHLY MDQ MAY:	200
MONTHLY MDQ JUNE:	150
MONTHLY MDQ JULY:	150
MONTHLY MDQ AUGUST:	150
MONTHLY MDQ SEPTEMBER:	250
MONTHLY MDQ OCTOBER:	300
MONTHLY MDQ NOVEMBER:	300
MONTHLY MDQ DECEMBER:	400

NUMBER OF RECEIPT POINTS:	11
NUMBER OF DELIVERY POINTS:	1

DELIVERY POINTS

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL01	400
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL02	400
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL03	300
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL04	200
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL05	200
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL06	150
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL07	150
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL08	150
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL09	250
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL10	300
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL11	300
020430	DELTA-JEFFERSONVILLE KY	DELTA NATURAL GAS CO, INC.	MONTGOMERY	KY	02	D	087	DQL12	400

TSP: 4052 - TENNESSEE GAS PIPELINE AGENT: 6458 - DELTA NAT GAS SVC REQ: 6458 - DELTA NAT GAS

Exhibit 3-7

Contract No.: 2516-FTGTGP

Rate Sch: Term Start: Term End:

Eff. From: 8/27/2018 Eff. Thru: 11/1/2018

Eff. From	Eff. Thru	Cycle	Rate Code	Rate Component	Rate	Rate Type
11/01/2018	11/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	RESV	11.034000	MAX
10/01/2018	10/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	RESV	11.266300	MAX
09/01/2018	09/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	RESV	11.391300	MAX
08/01/2018	08/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	RESV	11.891400	MAX

Exhibit 3-8

NICHOLASVILLE
FT-G TRANSPORTATION CONTRACT NO. 2555
RATE SCHEDULE FT-G

SERVICE PACKAGE NUMBER:	2555
TERM:	NOVEMBER 1, 2014 TO OCTOBER 31, 2019

MONTHLY MDQ JANUARY:	8,561
MONTHLY MDQ FEBRUARY:	8,561
MONTHLY MDQ MARCH:	5,600
MONTHLY MDQ APRIL:	4,000
MONTHLY MDQ MAY:	2,800
MONTHLY MDQ JUNE:	2,000
MONTHLY MDQ JULY:	2,000
MONTHLY MDQ AUGUST:	2,000
MONTHLY MDQ SEPTEMBER:	2,000
MONTHLY MDQ OCTOBER:	3,644
MONTHLY MDQ NOVEMBER:	5,000
MONTHLY MDQ DECEMBER:	8,561

NUMBER OF RECEIPT POINTS:	12
NUMBER OF DELIVERY POINTS:	1

DELIVERY POINTS

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	QTY	METER-TQ
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL01	8,561
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL02	8,561
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL03	5,600
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL04	4,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL05	2,800
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL06	2,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL07	2,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL08	2,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL09	2,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL10	3,644
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL11	5,000
020248	DELTA-NICHOLASVILLE KY	DELTA NATURAL GAS CO, INC.	GARRARD	KY	02	D	087	DQL12	8,561

TSP: 4052 - TENNESSEE GAS PIPELINE AGENT: 6458 - DELTA NAT GAS SVC REQ: 6458 - DELTA NAT GAS

Exhibit 3-9

Contract No.: 2555-FTGTGP

Rate Sch: Term Start: Term End:

Eff. From: 8/27/2018 Eff. Thru: 11/1/2018

Eff. From	Eff. Thru	Cycle	Rate Code	Rate Component	Rate	Rate Type
11/01/2018	11/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	RESV	11.315000	MAX
10/01/2018	10/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	RESV	11.892500	MAX
09/01/2018	09/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	RESV	11.892200	MAX
08/01/2018	08/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	RESV	11.892200	MAX

Exhibit 3-10

WEST BEND
FT-G TRANSPORTATION CONTRACT NO. 9069
RATE SCHEDULE FT-G

SERVICE PACKAGE NUMBER: 9069
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019

MONTHLY MDQ JANUARY:	250
MONTHLY MDQ FEBRUARY:	250
MONTHLY MDQ MARCH:	150
MONTHLY MDQ APRIL:	75
MONTHLY MDQ MAY:	50
MONTHLY MDQ JUNE:	50
MONTHLY MDQ JULY:	50
MONTHLY MDQ AUGUST:	50
MONTHLY MDQ SEPTEMBER:	100
MONTHLY MDQ OCTOBER:	100
MONTHLY MDQ NOVEMBER:	175
MONTHLY MDQ DECEMBER:	250

NUMBER OF RECEIPT POINTS: 1
NUMBER OF DELIVERY POINTS: 1

DELIVERY POINTS

METER	METER NAME	INTERCONNECT PARTY NAME	COUNTY	ST	ZONE	R/D	LEG	METER TQ	BILLABLE TQ	MONTH
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	250	250	01
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	250	250	02
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	150	150	03
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	75	75	04
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	50	50	05
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	50	50	06
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	50	50	07
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	50	50	08
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	100	100	09
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	100	100	10
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	175	175	11
020813	DELTA-WEST BEND SALES	DELTA NATURAL GAS CO, INC.	POWELL	KY	02	D	087	250	250	12

TSP: 4052 - TENNESSEE GAS PIPELINE AGENT: 6458 - DELTA NAT GAS SVC REQ: 6458 - DELTA NAT GAS

Exhibit 3-11

Contract No.: 9069-FTGTGP

Rate Sch: Term Start: Term End:

Eff. From: 8/27/2018 Eff. Thru: 11/1/2018

Eff. From	Eff. Thru	Cycle	Rate Code	Rate Component	Rate	Rate Type
11/01/2018	11/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
11/01/2018	11/30/2018	ANNUAL	RESV	RESV	10.421900	MAX
10/01/2018	10/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
10/01/2018	10/31/2018	ANNUAL	RESV	RESV	10.641300	MAX
09/01/2018	09/30/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
09/01/2018	09/30/2018	ANNUAL	RESV	RESV	10.641300	MAX
08/01/2018	08/31/2018	ANNUAL	CMDY	PSIMBTRP	0.000900	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	PSGHG	0.021600	MAX
08/01/2018	08/31/2018	ANNUAL	RESV	RESV	10.641300	MAX

DELTA NATURAL GAS COMPANY, INC.
COLUMBIA GAS TRANSMISSION MAXIMUM DAILY QUANTITIES
VOLUMES SHOWN IN DTH

CUMBERLAND

METER NAME	METER NO.	MDQ
MANCHESTER	METER #805992	5,100
BEATTYVILLE	METER #832867	300
	TOTAL	5,400

STANTON

METER NAME	METER NO.	MDQ
STANTON	METER #800803	2,530

WINCHESTER

METER NAME	METER NO.	MDQ
KINGSTON-TERRILL	METER #800809	2,270
FRENCHBURG	METER #803544	280
OWINGSVILLE	METER #803545	1,030
CAMARGO	METER #803563	340
SHARPSBURG	METER #803564	220
	TOTAL	4,140

NORTH MIDDLETOWN

METER NAME	METER NO.	MDQ
NORTH MIDDLETOWN	METER #803512	310

MT. OLIVET

METER NAME	METER NO.	MDQ
MT. OLIVET	METER #804148	500

CUMBERLAND
GTS SERVICE AGREEMENT NO.: 37813
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	5,400 DTH/DAY
STORAGE CONTRACT QUANTITY:	177,662 DTH
ANNUAL GTS QUANTITY:	98,200 DTH/YR
TERM:	NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		1,800

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
34	CUMBERLAND	805992	MANCHESTER	5,100	265 PSIG
34	CUMBERLAND	832867	BEATTYVILLE	300	230 PSIG

Exhibit 3-14

STANTON
GTS SERVICE AGREEMENT NO.: 37814
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	6,663 DTH/DAY
STORAGE CONTRACT QUANTITY:	83,255 DTH
ANNUAL GTS QUANTITY:	72,874 DTH/YR
TERM:	NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801	TCO-LEACH	4,133
801	TCO-LEACH	801	TCO-LEACH	4,976

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
35	STANTON	800803	STANTON	2,530	200 PSIG
801	TCO-LEACH	801	TCO-LEACH	4,133	
801	TCO-LEACH	801	TCO-LEACH	4,976	

Exhibit 3-15

WINCHESTER
GTS SERVICE AGREEMENT NO.: 37815
RATE SCHEDULE GTS

TRANSPORTATION DEMAND: 4,950 DTH/DAY
STORAGE CONTRACT QUANTITY: 162,857 DTH
ANNUAL GTS QUANTITY: 117,101 DTH/YR
TERM: NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		1,650

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
36-12	WINCHESTER	800809	KINGSTON-TERRILL	2,270	200 PSIG
36-14	WINCHESTER	803544	FRENCHBURG	280	150 PSIG
36-10	WINCHESTER	803545	OWINGSVILLE	1,030	400 PSIG
36-12	WINCHESTER	803563	CAMARGO	340	150 PSIG
36-10	WINCHESTER	803564	SHARPSBURG	220	100 PSIG
53	WINCHESTER	803512	NORTH MIDDLETOWN	310	100 PSIG
47	WINCHESTER	804148	MT. OLIVET	500	150 PSIG

CITY OF NORTH MIDDLETOWN
GTS SERVICE AGREEMENT NO.: 37948
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	310 DTH/DAY
STORAGE CONTRACT QUANTITY:	10,216 DTH
ANNUAL GTS QUANTITY:	12,686 DTH/YR
TERM:	NOVEMBER 1, 1993 THRU OCTOBER 31, 1994 AND FROM YEAR-TO-YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		103

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
53	CITY OF NORTH MIDDLETOWN	803512	NORTH MIDDLETOWN	310	100 PSIG

ROLLED INTO DELTA-WINCHESTER

MT. OLIVET
GTS SERVICE AGREEMENT NO.: 37954
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	500 DTH/DAY
STORAGE CONTRACT QUANTITY:	16,434 DTH
ANNUAL GTS QUANTITY:	29,127 DTH/YR
TERM:	NOVEMBER 1, 1993 THRU OCTOBER 31, 1994 AND YEAR-TO-YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		167

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
47	MT. OLIVET	804148	MT. OLIVET	500	150 PSIG

ROLLED INTO DELTA-WINCHESTER

Exhibit 3-18

STANTON
ASSIGNMENT AGREEMENT NO.: 43827
RATE SCHEDULE FTS-1

TRANSPORTATION DEMAND: 860 DTH/DAY
TERM: NOVEMBER 1, 2015 TO OCTOBER 31, 2020

PRIMARY RECEIPT POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
2700010	CGT-RAYNE	860

PRIMARY DELIVERY POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	860

Exhibit 3-19

CUMBERLAND
ASSIGNMENT AGREEMENT NO.: 43828
RATE SCHEDULE FTS-1

TRANSPORTATION DEMAND: 1,836 DTH/DAY
TERM: NOVEMBER 1, 2015 TO OCTOBER 31, 2020

PRIMARY RECEIPT POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
2700010	CGT-RAYNE	1,836

PRIMARY DELIVERY POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	1,836

Exhibit 3-20

WINCHESTER
ASSIGNMENT AGREEMENT NO.: 43829
RATE SCHEDULE FTS-1

TRANSPORTATION DEMAND: 1,682 DTH/DAY

TERM: NOVEMBER 1, 2015 TO OCTOBER 31, 2020

PRIMARY RECEIPT POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
2700010	CGT-RAYNE	1,682

PRIMARY DELIVERY POINTS

MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	1,682

Exhibit 3-21

Currently Effective Rates
Applicable to Rate Schedule GTS
Rate Per Dth

		Base Tariff Rate 1/ 2/	TCRA Rates	EPCA Rates	OTRA Rates	CCRM Rates	Total Effective Rate 2/	Daily Rate 2/
Rate Schedule GTS								
Commodity								
Maximum	¢	64.84	1.52	1.30	0.10	9.78	77.54	77.54
Minimum	¢	3.08	0.05	0.80	0.00	0.00	3.93	3.93
MFCC	¢	61.76	1.47	0.50	0.10	9.78	73.61	73.61

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.

2/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 34 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

RETAINAGE PERCENTAGES

Transportation Retainage	1.454%
Gathering Retainage	4.500%
Storage Gas Loss Retainage	0.540%
Ohio Storage Gas Loss Retainage	0.610%
Columbia Processing Retainage 1/	0.000%

1/ The Columbia Processing Retainage shall be assessed separately from the processing retainage applicable to third party processing plants set forth in Section 25.3 (f) of the General Terms and Conditions.

Currently Effective Rates
Applicable to Rate Schedule FTS-1
Rates in Dollars per Dth

Rate Schedule FTS-1	Base Rate (1) 1/	Total Effective Rate (2) 1/	Daily Rate (3) 1/
Market Zone			
Reservation Charge			
Maximum	4.170	4.170	0.1371
Minimum	0.000	0.000	0.000
Commodity			
Maximum	0.0109	0.0109	0.0109
Minimum	0.0109	0.0109	0.0109
Overrun			
Maximum	0.1480	0.1480	0.1480
Minimum	0.0109	0.0109	0.0109

1/ Excludes the Annual Charge Adjustment (ACA) Surcharge. An ACA Commodity surcharge per Dth shall be assessed where applicable pursuant to Section 154.402 of the Commission's Regulations and in accordance with Section 31 of the GTC of Transporter's FERC Gas Tariff. The ACA unit charge authorized for each fiscal year (commencing October 1) by the Commission and posted on its website (http://www.ferc.gov) is incorporated herein by reference.

RETAINAGE RATES

	Company Use & Unaccounted For 1/	Surcharge	Total Effective Rate
Market Zone 2/			
(mainline)	0.858%	-0.156%	0.702%
(former onshore)	0.417%	-0.157%	0.260%

1/ For service provided over Transporter's East Lateral Efficiency Optimization Project facilities, Shipper's delivered quantities will be reduced to reflect actual lost and unaccounted for quantities.

2/ Agreements containing the terms "Forwardhaul," "Market Zone – Forwardhaul," "Backhaul," "Market Zone – Backhaul," or words of similar import to describe the applicable retainage rate will be assessed the Market Zone mainline retainage rate.

DELTA NATURAL GAS COMPANY, INC.
MAXIMUM DAILY STORAGE INJECTIONS AND WITHDRAWALS
VOLUMES SHOWN IN DTH

METER	MAXIMUM INJECTIONS	MAXIMUM WITHDRAWALS
BEREA	1,083	3,824
NICHOLASVILLE	2,356	4,917
JEFFERSONVILLE	89	291
SALT LICK, FARMERS & KINDER/HILDA	302	1,128
TOTAL	3,830	10,160

Exhibit 4-2

SALT LICK, FARMERS & KINDER-HILDA
FS GAS STORAGE CONTRACT NO. 2362
RATE SCHEDULE FS - MARKET AREA

CONTRACT NO.:	2362
CONTRACT MSQ:	45,300
TERM:	NOVEMBER 1, 2014 TO OCTOBER 31, 2019
SERVICE POINT:	TRANSPORTER'S COMPRESSOR STATION 87

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	1,128
060020	0	01	INJECTION	302

Exhibit 4-3

BEREA
FS GAS STORAGE CONTRACT NO. 2363
RATE SCHEDULE FS - MARKET AREA

CONTRACT NO.: 2363
CONTRACT MSQ: 162,411
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019
SERVICE POINT: TRANSPORTER'S COMPRESSOR STATION 87

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	3,824
060020	0	01	INJECTION	1,083

Exhibit 4-4

NICHOLASVILLE
FS GAS STORAGE CONTRACT NO. 2364
RATE SCHEDULE FS - MARKET AREA

CONTRACT NO.: 2364
CONTRACT MSQ: 179,911
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019
SERVICE POINT: TRANSPORTER'S COMPRESSOR STATION 87

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	3,684
060020	0	01	INJECTION	1,200

Exhibit 4-5

JEFFERSONVILLE
FS GAS STORAGE CONTRACT NO. 2365
RATE SCHEDULE FS - PRODUCTION AREA

CONTRACT NO.: 2365
CONTRACT MSQ: 13,358
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019
SERVICE POINT: TRANSPORTER'S COMPRESSOR STATION 87

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	291
060020	0	01	INJECTION	89

Exhibit 4-6

NICHOLASVILLE
FS GAS STORAGE CONTRACT NO. 2366
RATE SCHEDULE FS - PRODUCTION AREA

CONTRACT NO.: 2366
CONTRACT MSQ: 173,399
TERM: NOVEMBER 1, 2014 TO OCTOBER 31, 2019
SERVICE POINT: TRANSPORTER'S COMPRESSOR STATION 87

METER	AMENDMENT	ZONE	W/I	MAXIMUM DAILY QUANTITY
070020	0	01	WITHDRAWAL	1,233
060020	0	01	INJECTION	1,156

DELTA NATURAL GAS COMPANY, INC.
MAXIMUM DAILY STORAGE INJECTIONS AND WITHDRAWALS
VOLUMES SHOWN IN DTH

METER	MAXIMUM INJECTIONS	MAXIMUM WITHDRAWALS
STANTON	2,530	2,530
KINGSTON-TERRILL	2,270	2,270
FRENCHBURG	280	280
OWINGSVILLE	1,030	1,030
CAMARGO	340	340
SHARPSBURG	220	220
MANCHESTER	5,100	5,100
BEATTYVILLE	300	300
NORTH MIDDLETOWN	310	310
MT. OLIVET	500	500
TOTAL	12,880	12,880

Exhibit 4-8

CUMBERLAND
GTS SERVICE AGREEMENT NO.: 37813
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	5,400 DTH/DAY
STORAGE CONTRACT QUANTITY:	177,662 DTH
ANNUAL GTS QUANTITY:	98,200 DTH/YR
TERM:	NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		1,800

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
34	CUMBERLAND	805992	MANCHESTER	5,100	265 PSIG
34	CUMBERLAND	832867	BEATTYVILLE	300	230 PSIG

Exhibit 4-9

STANTON
GTS SERVICE AGREEMENT NO.: 37814
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	6,663 DTH/DAY
STORAGE CONTRACT QUANTITY:	83,255 DTH
ANNUAL GTS QUANTITY:	72,874 DTH/YR
TERM:	NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801	TCO-LEACH	4,133
801	TCO-LEACH	801	TCO-LEACH	4,976

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
35	STANTON	800803	STANTON	2,530	200 PSIG
801	TCO-LEACH	801	TCO-LEACH	4,133	
801	TCO-LEACH	801	TCO-LEACH	4,976	

Exhibit 4-10

WINCHESTER
GTS SERVICE AGREEMENT NO.: 37815
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	4,950 DTH/DAY
STORAGE CONTRACT QUANTITY:	162,857 DTH
ANNUAL GTS QUANTITY:	117,101 DTH/YR
TERM:	NOVEMBER 1, 2015 AND YEAR TO YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		1,650

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
36-12	WINCHESTER	800809	KINGSTON-TERRILL	2,270	200 PSIG
36-14	WINCHESTER	803544	FRENCHBURG	280	150 PSIG
36-10	WINCHESTER	803545	OWINGSVILLE	1,030	400 PSIG
36-12	WINCHESTER	803563	CAMARGO	340	150 PSIG
36-10	WINCHESTER	803564	SHARPSBURG	220	100 PSIG
53	WINCHESTER	803512	NORTH MIDDLETOWN	310	100 PSIG
47	WINCHESTER	804148	MT. OLIVET	500	150 PSIG

CITY OF NORTH MIDDLETOWN
GTS SERVICE AGREEMENT NO.: 37948
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	310 DTH/DAY
STORAGE CONTRACT QUANTITY:	10,216 DTH
ANNUAL GTS QUANTITY:	12,686 DTH/YR
TERM:	NOVEMBER 1, 1993 THRU OCTOBER 31, 1994 AND FROM YEAR-TO-YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		103

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
53	CITY OF NORTH MIDDLETOWN	803512	NORTH MIDDLETOWN	310	100 PSIG

ROLLED INTO DELTA-WINCHESTER

MT. OLIVET
GTS SERVICE AGREEMENT NO.: 37954
RATE SCHEDULE GTS

TRANSPORTATION DEMAND:	500 DTH/DAY
STORAGE CONTRACT QUANTITY:	16,434 DTH
ANNUAL GTS QUANTITY:	29,127 DTH/YR
TERM:	NOVEMBER 1, 1993 THRU OCTOBER 31, 1994 AND YEAR-TO-YEAR THEREAFTER

PRIMARY RECEIPT POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAXIMUM DAILY QUANTITY
801	TCO-LEACH	801		167

PRIMARY DELIVERY POINTS

SCHEDULING POINT NO.	SCHEDULING POINT NAME	MEASURING POINT NO.	MEASURING POINT NAME	MAX DAILY DELIVERY OBLIGATION	MIN DELIVERY PRESSURE OBLIGATION
47	MT. OLIVET	804148	MT. OLIVET	500	150 PSIG

ROLLED INTO DELTA-WINCHESTER

Exhibit 4-13

DELTA NATURAL GAS COMPANY, INC.
CALCULATIONS OF CANADA MOUNTAIN DELIVERABILITY

FIELD PRESSURE (PSIG)	FIELD DELIVERABILITY (MCF/D)
985	79,969
900	69,269
800	57,009
700	45,078
600	33,404
500	21,776
400	9,336

CUSTOMER NOMINATION FORM

DELTA NATURAL GAS COMPANY, INC.
3617 Lexington Road
Winchester, KY 40391
Attn: Wayne T. Hunter II
Coordinator - Transmission & Gas Supply

Phone #: 859-744-6171, Ext. 1131
Fax #: 800-482-7623
Email: whunter@deltagas.com

SHIPPER		END - USER	
Name:	____________	Name:	____________
Address:	____________	Address:	____________
Contact:	____________	Contact:	____________
Phone #:	____________	Phone #:	____________
Fax #:	____________	Fax #:	____________
Email:	____________	Email:	____________

Delivering Pipeline: ____________

Contract #: ____________

Meter Name: ____________

Meter Number: ____________

Date of Request: ____________

Daily Nom Breakdown (if necessary)

9/1/2018	0
9/2/2018	0
9/3/2018	0
9/4/2018	0
9/5/2018	0
9/6/2018	0
9/7/2018	0
9/8/2018	0
9/9/2018	0
9/10/2018	0
9/11/2018	0
9/12/2018	0
9/13/2018	0
9/14/2018	0
9/15/2018	0
9/16/2018	0
9/17/2018	0
9/18/2018	0
9/19/2018	0
9/20/2018	0
9/21/2018	0
9/22/2018	0
9/23/2018	0
9/24/2018	0
9/25/2018	0
9/26/2018	0
9/27/2018	0
9/28/2018	0
9/29/2018	0
9/30/2018	0
	0
	0

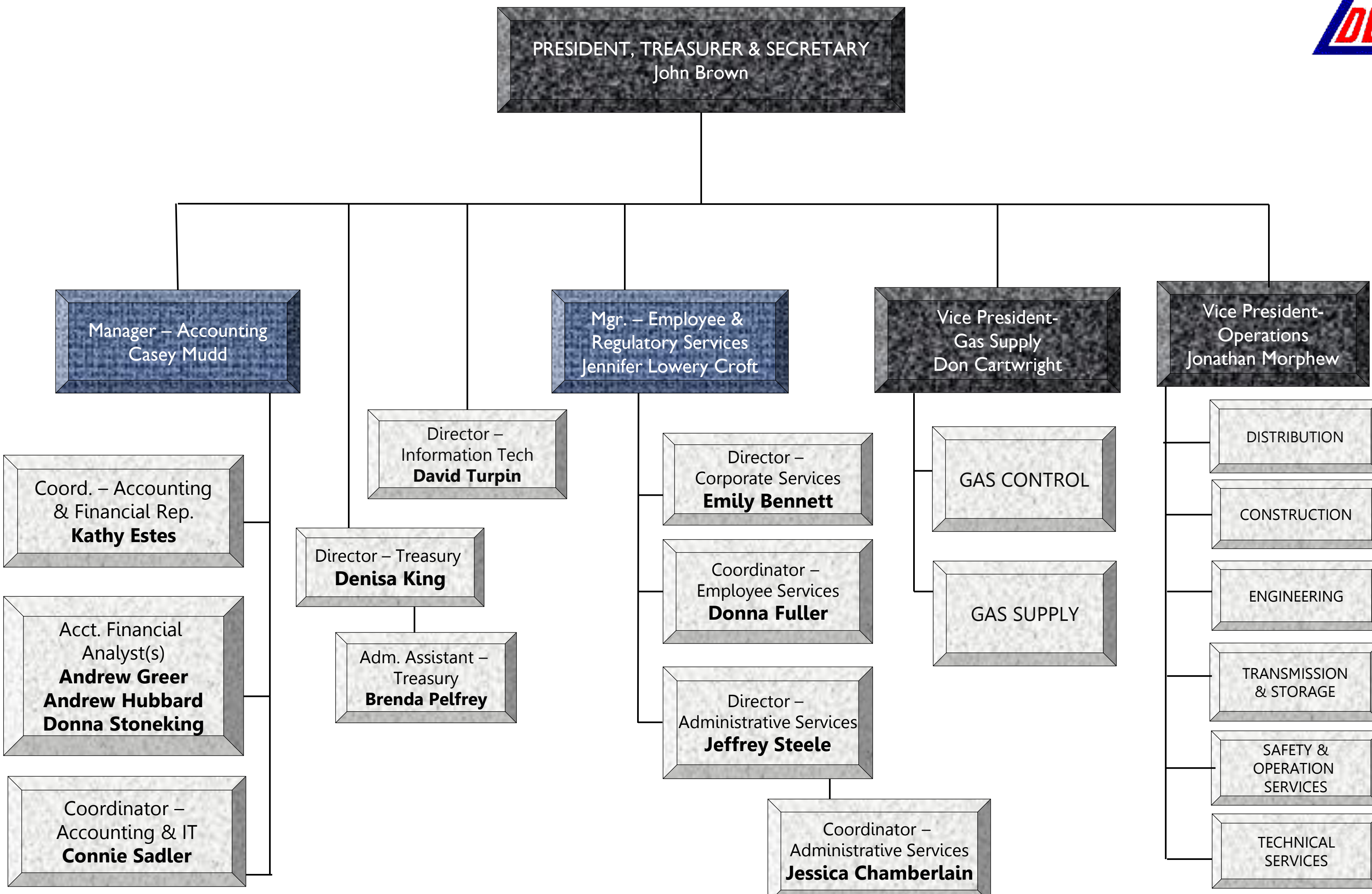
	Effective Dates From	To	Daily Quantity (Dth/d)	Total Quantity (Dth)
Previous Nomination:				
New Nomination:				
Total:				

THIS FORM IS TO BE USED BY ANY SHIPPER WHICH IS DELIVERING GAS INTO A METER WHICH IS OPERATED BY DELTA NATURAL GAS COMPANY, INC. THIS FORM MUST BE COMPLETED AND FAXED OR EMAILED TO DELTA PRIOR TO THE APPLICABLE DELIVERING PIPELINE'S NOMINATION DEADLINE.

Exhibit 11-1

Corporate & Department Levels

Chart I



Gas Supply

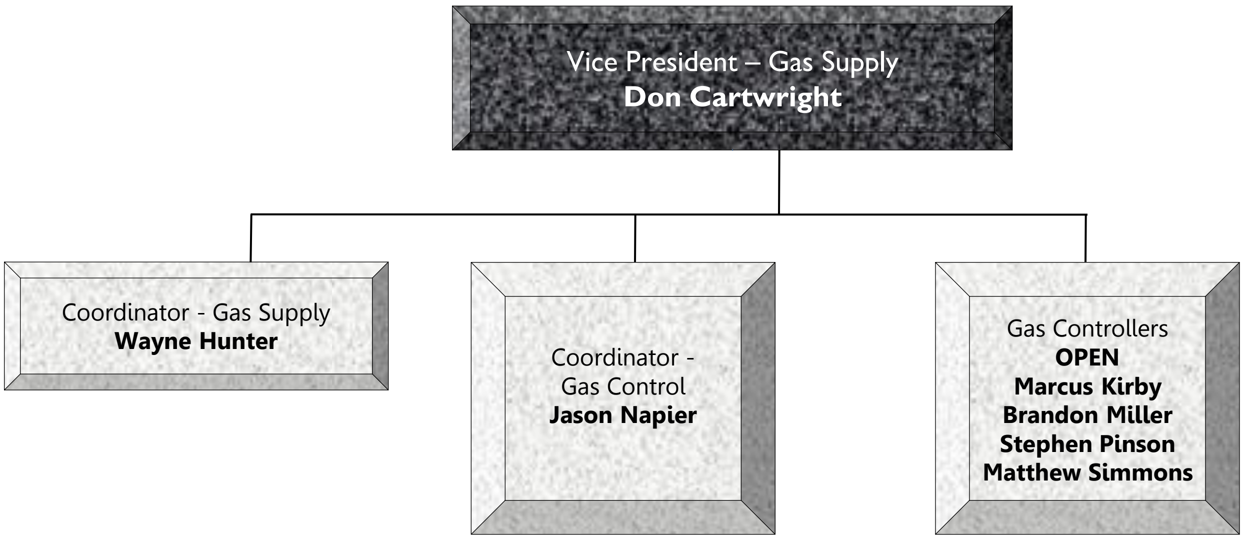


Chart II

Operations Level

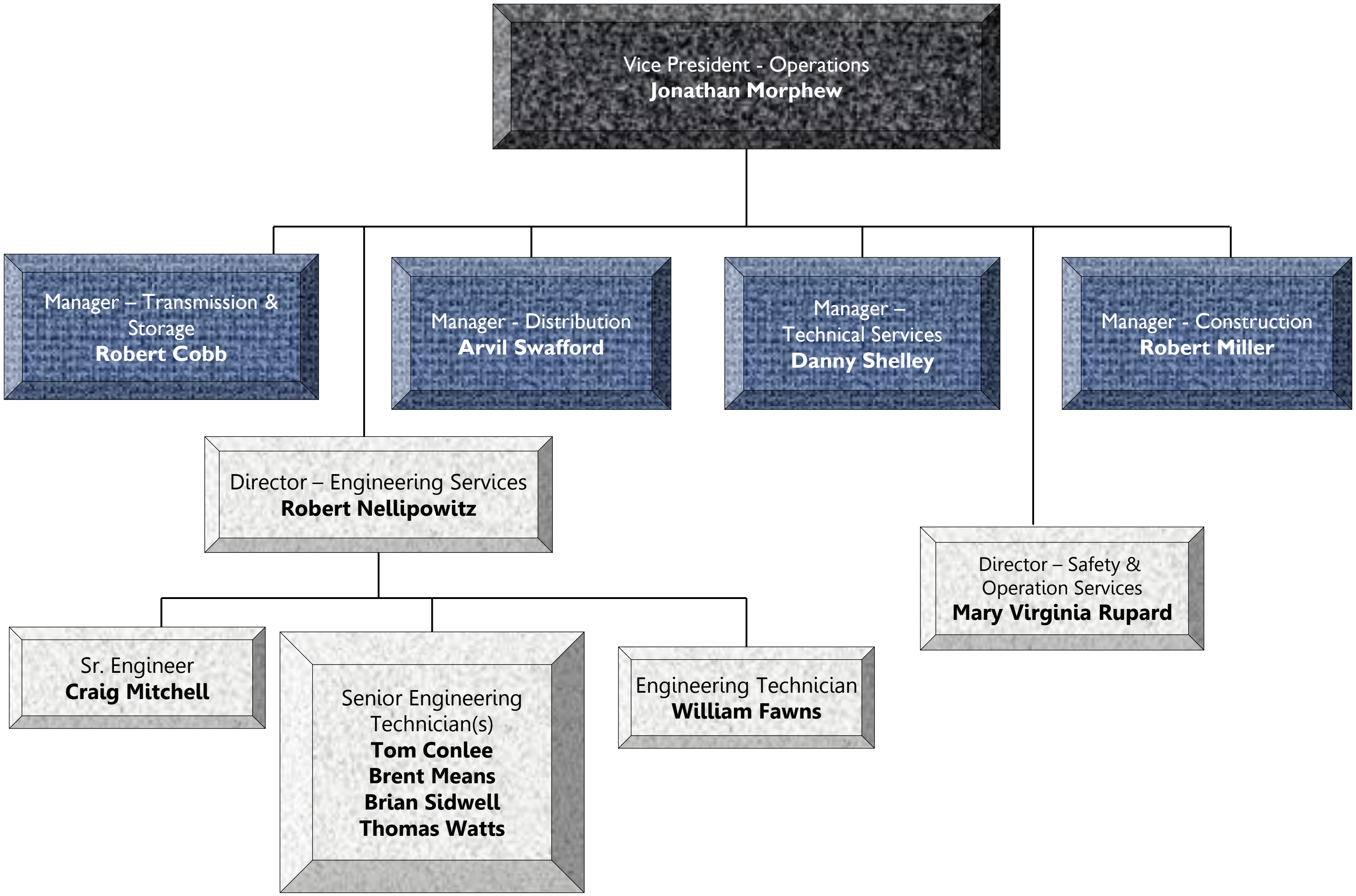
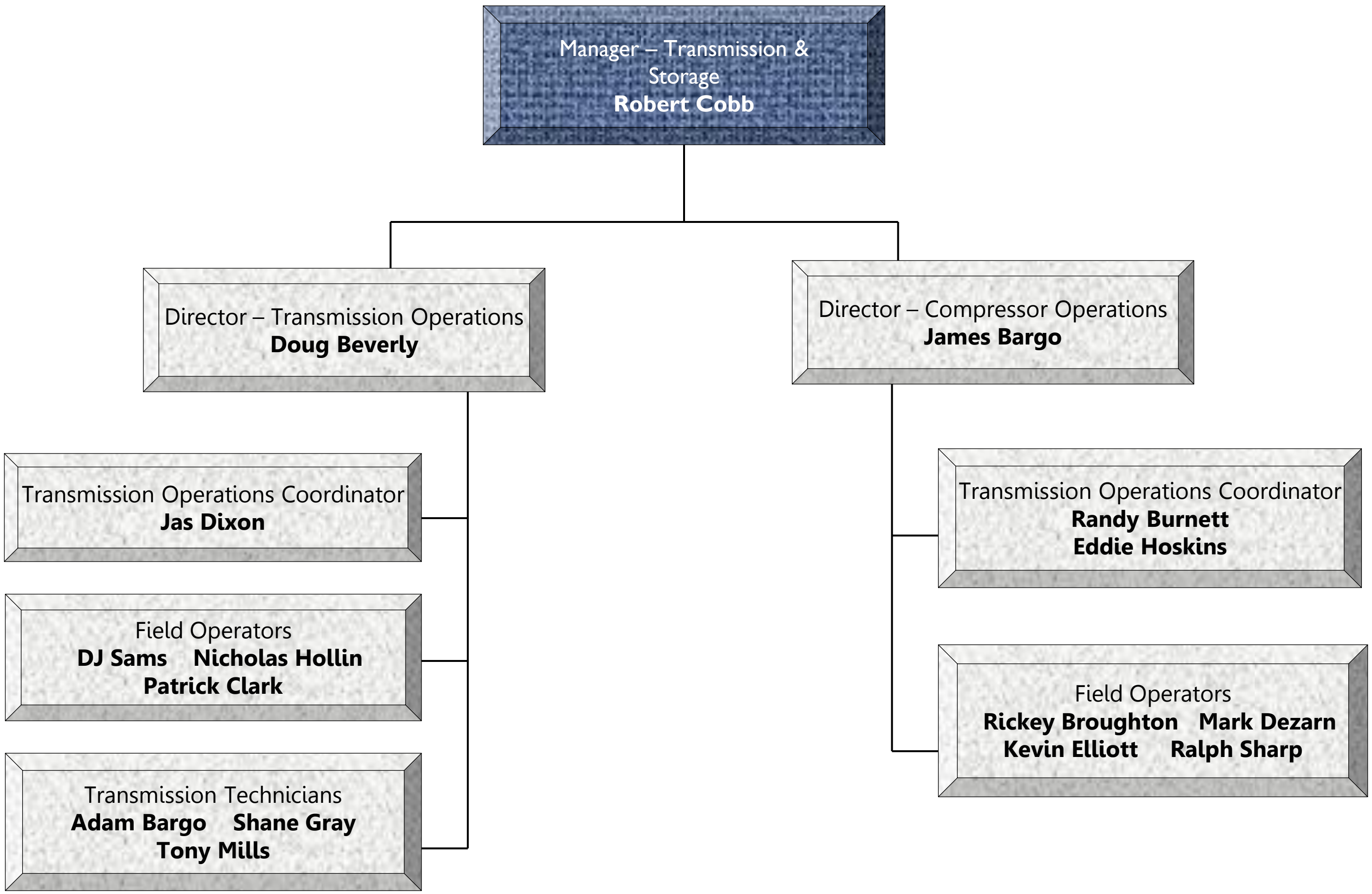


Chart III

09.21.2018

Transmission Level

Chart III (a)



07.01.2018

Distribution / Customer Service Level

Manager - Distribution
Arvil Swafford

Senior District Manager – Distribution
Mark Norvell

District Manager – Distribution
Bobby Bargo Darrell Baker
Kevin Partin Lawrence Riley
Ricky Terrill

District Customer Service Coordinators
Brad Bowman
Shawn Clayton
Mark Crowe
Frankie Gilbert
Jason Gaddis

Senior Customer Service Representative(s)
Jason Asher, Terry Baker, Tim Buckler, John David Caudill, Jimmy Hamblin, Scotty McQueen, Anthony Maiden, Glenn Montgomery, James Neace, Mike Scott, Nathan Shackelford, Jowayne Schell, Doug Teater

Customer Service Representative(s)
Andrew Applegate, Josh Adams, John Browning, Robbie Byrd, Shawn Carpenter, Brian Evans, Jimmy Hoskins, Dwayne Jamison, Robert Kirby, Jamie Mills, John Mills, Clint Orme, Mark Redmond, Cale Rose, James Sadler, Ross Tanner, Christian Warren, Richard Tye, Joshua Vanderpool, David Whitaker

Senior Customer Representative(s)
Sherry Barnes, Alisha Lawson, Cricket Luckadoo, Lisa Hager, Carol Parsons, Brenda Sorrell

Customer Representative(s)
Donna Baker, Jennifer Bingham, Julie Bland, Wendi Crawford, Donna Herrington, Tammy Mayle, Cantina Miller

Chart III (b)

09.21.2018

Construction Level

Chart III (c)

MANAGER – CONSTRUCTION
Robert Miller

Construction Supervisors
Chad Crawford, Sawyer Messer
Danny Rogers, James McNabb
David Stivers, Alvin Hatton

Inspector
Tommy Mills
OPEN

Welders
Johnny Gray
Tonny Jenkins
Vernon Engle
Tim Wynn

Construction Technicians
Brandon Brock, Dale Burnett,
James Hinkle, Marty Hollin,
Wesley Morton, Jeremy Robbins,
Ty Stewart, Elijah Wells,
Scotty Williams, OPEN (2)

Equipment Operators
Patrick Broughton
Cooper Carson
Jamie Cooke
Robbie Mulcahy
Charley Parks
Charlie Poor

Technical Services Level

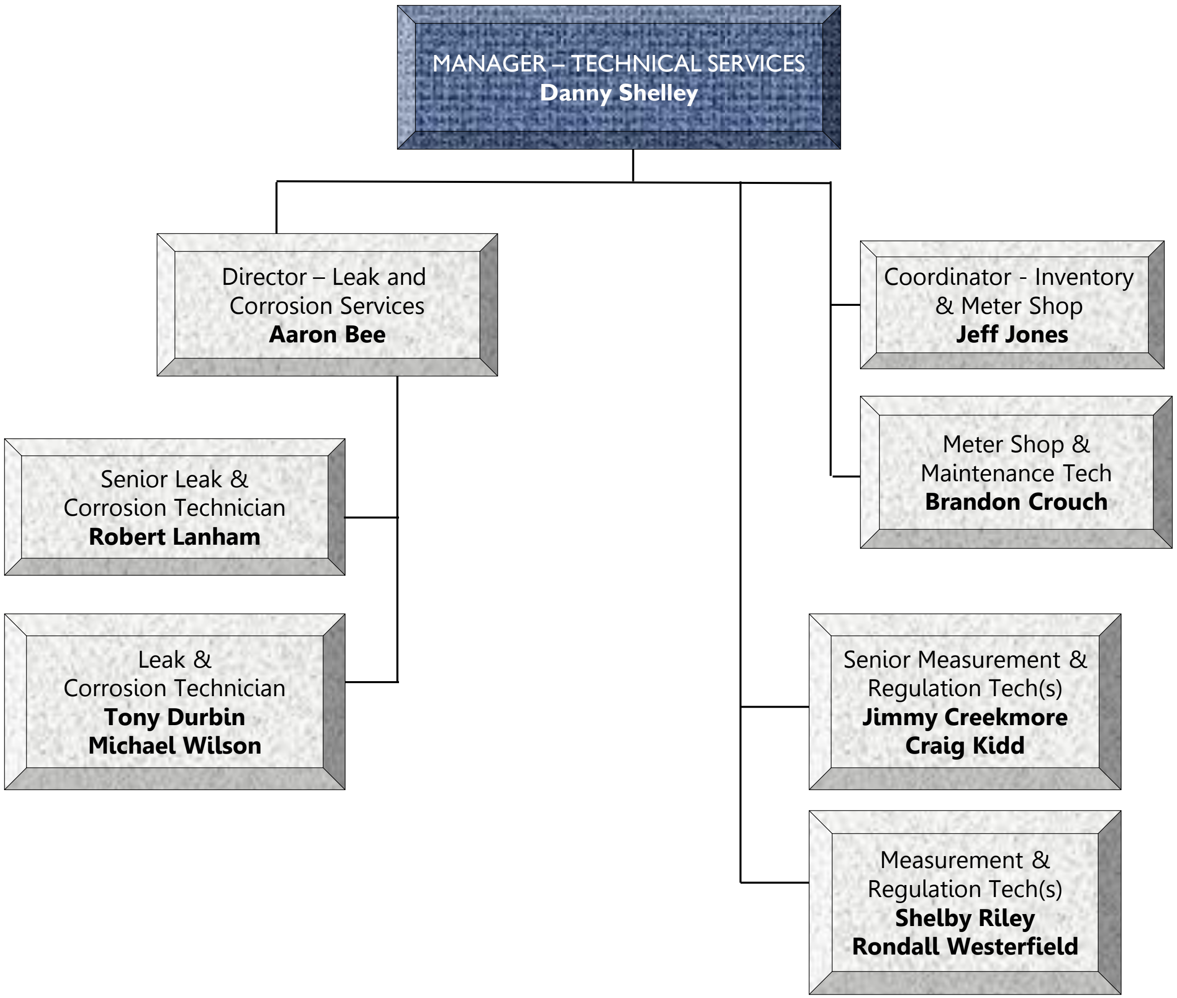


Chart III (d)

07.01.2018

Delta Natural Gas Company, Inc.
Job Description

Job Title: **Vice President – Gas Supply**
Reports To: President, Treasurer and Secretary
Section: Gas Supply
Effective Date: 07/01/2018

Function:

Plans, directs and acts as liaison in all gas supply matters with gas suppliers, pipelines, transporters on the Company's system, large volume end users, federal agencies and the Kentucky Public Service Commission. Seeks opportunities to enhance the Company's production, transmission and distribution capabilities.

Duties:

1. Directs and coordinates the activities of the Coordinator - Gas Control, Coordinator - Gas Supply and Gas Controllers.
2. Oversees and directs gas operations planning with respect to gas supply and load forecasts and assures adequate gas supplies to meet customers' needs. Prepares monthly, annual and five-year gas requirements plans. Provides technical assistance for analysis of the Company's short- and long-term system requirements and for analysis of the Company's and other's pipeline systems. Participates in the budget preparation process as appropriate.
3. Works closely with the Vice President -- Operations and the Manager -- Transmission & Storage to ensure efficient system operation to meet system gas requirements, achieve storage injection/withdrawal goals and to meet transportation objectives.
4. Responsible for gas supply planning and gas purchasing. Oversees and directs on-system and off-system gas transportation services to assure maximum utilization of transportation opportunities.
5. Acts as the Company's initial contact person concerning new producers and new production on or near the Company's pipelines. Coordinates with the Vice President -- Operations and the Manager -- Transmission & Storage to determine required connecting facilities and possible tap locations.
6. Responsible for assimilating and providing well pressure and production volume information, for working with the Company's consultant to annually update the Company's well reserve evaluation, and for maintaining reserve records for company owned wells.
7. Maintains inventory analysis and verification records on the Canada Mountain Storage Field, works with the Company's consultant on evaluations of the Field's data and monitors drilling activity in the vicinity of the Field.
8. Directs and coordinates sales to large volume end users, marketers, or other parties.
9. Responsible for being the primary contact person with suppliers, transporters, interstate pipelines and large end-users. Responsible for the negotiation, execution and administration of gas supply contracts, gas sales contracts, on-system transportation agreements, off-system transportation agreements, regulatory compliance/reporting and for billing approvals.
10. Responsible for providing data to Accounting Department on a timely basis for monthly billing and payment purposes, and for approving volumes and rates on invoices rendered and invoices received from suppliers and pipelines. Ensures that areas of responsibility adhere to monthly closing schedules.
11. Represents the Company with gas supply related trade groups and coordinates the Company's involvement with attorneys on FERC related issues.
12. Monitors and ensures compliance with federal and state laws and orders relative to the sale and use of gas, including Interstate Transporters' tariffs, pricing and contract compliance and reporting.
13. Appraises and evaluates the profitability of each individual deal, and compares results with established budgets, goals and objectives; formulates and takes necessary corrective action where appropriate.
14. Guides, facilitates and reviews the performance of internal controls and maintenance of internal control documentation within areas of supervision.
15. Promotes effective communication and cooperation among all employees enabling timely and accurate information to flow inside and outside the organization.
16. Performs any and all other duties assigned by authorized personnel.

QUALIFICATIONS

TITLE: VICE PRESIDENT – Gas Supply

EDUCATION:

- Bachelor's Degree in Business or Engineering or equivalent experience

PROFESSIONAL CERTIFICATIONS:

- None required

PREVIOUS EXPERIENCE REQUIRED:

- Ten years related experience

OTHER JOB RESPONSIBILITIES:

Number of Employees Supervised:

- Direct: 7
- Indirect: 0

PUBLIC CONTACTS:

- Gas suppliers, producers, attorneys, large volume end users, vendors, other utilities, trade organizations, pipeline companies, PNG, Kentucky Public Service Commission staff and Federal Energy Regulatory Commission staff

OTHER JOB REQUIREMENTS:

- Must possess a valid driver's license
- Travel may be required

Remarks: In addition to the above qualifications all employees must meet the general qualifications and requirements pertaining to all jobs.

Delta Natural Gas Company, Inc.
Job Description

Job Title: Coordinator – Gas Supply

Reports To: Vice President – Gas Supply
Grade: E10
Section: Gas Supply
Effective Date: 07/01/2018

Function:

Under general supervision, develops historical customer usage factors and short-range and long-range projections. Monitors gas purchase agreements, gas sales agreements, gas transportation agreements, and gas leases for compliance. Maintains Company relations with suppliers, transporters, pipelines and large end users.

Duties:

1. Responsible for gas supply contract management including supply contracts, sales contracts and on-and off- system transportation agreements.
2. Responsible for providing gas accounting data to Accounting Department on a timely basis for monthly billing and payment purposes, and for approving volumes and rates on invoices rendered and invoices received from suppliers and pipelines.
3. Develops and maintains weather data and customer usage factors by service area.
4. Prepares short-range and long-range estimates of gas sales by customer classification and service area for internal use and to comply with supplier requests and regulatory requirements.
5. Responsible for scheduling and monitoring purchases and sales of gas.
6. Responsible for maintaining gas leases for compliance with shut-in royalty provisions, and for maintaining contract with property owners regarding lease provisions, assignments of leases, transfer orders and free gas customers.
7. Prepares and maintains gas supply, gas transportation, and storage reports for state and federal regulatory agencies, trade associations and for internal reporting purposes.
8. Responsible for receiving and responding to all on-system and off-system transportation nominations, including adjustments in volumes on existing arrangements and for providing information to Gas Control on a timely basis.
9. Responsible for monitoring on-system and off-system transportation arrangements for contract compliance, for reporting to regulatory agencies, and for billing accuracy. Responsible for scheduling transportation volumes on interstate pipelines.
10. Responsible for providing gas analysis and gas cost data for quarterly Gas Cost Recovery (GCR) filings and for periodic PSC reviews of gas costs.
11. Prepares monthly gas requirements plan by system and by customer classification and communicates total system requirements to interstate suppliers.
12. Responsible for maintaining Company relations with suppliers, transporters, interstate pipelines and large end users.
13. Perform assigned internal control activities and maintain internal control documentation.
14. Effectively communicate with others both inside and outside of the departments providing timely and accurate information.
15. Performs any and all other duties assigned by authorized personnel.

QUALIFICATIONS

TITLE: Coordinator – Gas Supply

EDUCATION:

- College Degree or Associate Degree in Accounting, Engineering or Business Administration preferred or equivalent experience

PROFESSIONAL CERTIFICATIONS:

- None required

PREVIOUS EXPERIENCE REQUIRED:

- Minimum five years in natural gas industry preferred

OTHER JOB RESPONSIBILITIES:

Number of Employees Supervised:

- Direct: 0
- Indirect: 0

PUBLIC CONTACTS:

- Regulatory agencies, pipeline companies, attorneys, large volume end users, transporters, producers, property owners and gas marketing firms

OTHER JOB REQUIREMENTS:

- Must possess a valid drivers license
- Travel may be required

Remarks: In addition to the above qualifications all employees must meet the general qualifications and requirements pertaining to all jobs.

Delta Natural Gas Company, Inc.
Job Description

Job Title: Coordinator – Gas Control

Reports To: Vice President – Gas Supply
Grade: E10
Section: Gas Supply
Effective Date: 07/01/2018

Function:

Under general supervision, performs various tasks relating to pipeline monitoring, flow control, gas analysis, gas accounting and emergency response.

Duties:

1. Maintains a detailed working knowledge of Delta's pipeline systems and dispatches transportation, purchase and storage volumes into and out of Delta's systems. Must be able to identify abnormal pipeline conditions, operate remote control equipment and dispatch field personnel to ensure safe pipeline operations.
2. Maintains the requisite computer skills to operate, troubleshoot and revise Company's SCADA system and other software systems to ensure accurate data. Responsible for recording data in spreadsheet and database files.
3. Responsible for developing and maintaining a program for gas analysis. Maintains the sampling/analysis equipment and ensures the accuracy. Responsible for maintaining appropriate results and records for billing third parties when appropriate.
4. Maintains a working knowledge of AGA Report No. 3 orifice measurement. Supervises measurement chart integration, computation of volumes (Mcf and Dth) and the timely providing of gas accounting information to the appropriate parties.
5. Responsible for keeping Control Room Management (CRM) records up to date in Control Room Information Management System data base for PSC audits according to company standard practices.
6. Maintains a working knowledge of all delivery/receipt points and contract accounts. Responsible for preparing monthly reports on transportation, storage, and off system supply volumes in a timely and accurate manner.
7. Maintains a working knowledge of Company's liquid processing facility. Responsible for monitoring and dispatching field personnel to ensure safe processing operations.
8. Monitors and records weather data to forecast daily system requirements.
9. Responsible for processing data and validations of EM Orifice Measurement.
10. Maintains a working knowledge of computer techniques, software, and telemetry to ensure efficient gas control operations. Responsible for training Gas Control personnel.
11. Handles swing shift scheduling for gas controllers and performs any and all Gas Control duties as required.
12. May be required to work abnormal hours and is subject to twenty four hour call.
13. Performs any and all other duties assigned by authorized personnel.

QUALIFICATIONS

TITLE: COORDINATOR – GAS CONTROL

EDUCATION:

- High School plus some technical training preferred. Knowledge of computer operations and spread sheet software required

PROFESSIONAL CERTIFICATIONS:

- None required

PREVIOUS EXPERIENCE REQUIRED:

- Minimum five years in natural gas industry preferred

OTHER JOB RESPONSIBILITIES:

Number of Employees Supervised:

- Direct: 0
- Indirect: 5

PUBLIC CONTACTS:

- Producers, marketers, pipeline companies, emergency personnel and customers.

OTHER JOB REQUIREMENTS:

- Must possess a valid drivers license
- Must become Operator qualified and complete pipeline training prior to going on shift

Remarks: In addition to the above qualifications all employees must meet the general qualifications and requirements pertaining to all jobs.

Delta Natural Gas Company, Inc.
Job Description

Job Title: Gas Controller

Reports To: Vice President – Gas Supply
Grade: N08
Section: Gas Supply
Effective Date: 07/01/2018

Function:

Under general supervision, performs various tasks relating to pipeline monitoring, flow control, gas analysis, gas accounting and emergency response.

Duties:

1. Maintains a detailed working knowledge of Delta's pipeline systems and dispatches transportation, purchase and storage volumes into and out of Delta's systems. Must be able to identify abnormal pipeline conditions, operate remote control equipment and dispatch field personnel to ensure safe pipeline operations.
2. Maintains the requisite computer skills to operate Company's SCADA system and other software systems to ensure accurate data. Responsible for recording data in spreadsheet and database files.
3. Maintains a working knowledge of the chromatographs to analyze gas and liquid samples.
4. Maintains a working knowledge of AGA Report Nol. 3. Must be able to calibrate and operate the chart integrator to ensure accurate volumetric data.
5. Receives calls on Company's emergency phone line and quickly dispatches company personnel as needed. Must maintain a working knowledge of emergency procedures involving gas supply.
6. Maintains a working knowledge of Company's Control Room Management procedures. Must record required data in Company's data base.
7. Responsible for chart integration.
8. Maintains a working knowledge of Company's liquid processing facility. Responsible for monitoring and dispatching field personnel to ensure safe processing operations.
9. Maintains daily system and emergency phone logs.
10. Shall be required to work shift work and subject to 24 hour call during relief shift.
11. Performs any and all other duties assigned by authorized personnel.

QUALIFICATIONS

TITLE: GAS CONTROLLER

EDUCATION:

- High School plus some technical training preferred. Knowledge of computer operations and spread sheet software required

PROFESSIONAL CERTIFICATIONS:

- None required

PREVIOUS EXPERIENCE REQUIRED:

- None - will be required to develop ability to operate and maintain chart integrator and chromatograph. Must develop the ability to operate personal computer software in conjunction with job responsibilities.

OTHER JOB RESPONSIBILITIES:

Number of Employees Supervised:

- Direct: 0
- Indirect: 0

PUBLIC CONTACTS:

- Producers, marketers, pipeline companies, emergency personnel and customers.

OTHER JOB REQUIREMENTS:

- Must possess a valid drivers license
- Must become Operator qualified and complete pipeline training prior to going on shift

Remarks: In addition to the above qualifications all employees must meet the general qualifications and requirements pertaining to all jobs.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Exhibit 13-1

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, 2013

☐ **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 ☐

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. $133,911,811.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. As of August 15, 2013, Delta Natural Gas Company, Inc. had outstanding 6,864,611 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, 2013, is incorporated by reference in Part III of this Report.

TABLE OF CONTENTS

PART I

Item 1. Business

General -

Delta Natural Gas Company, Inc. (Nasdaq: DGAS) distributes or transports natural gas to approximately 36,000 customers. Our distribution and transmission pipeline 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 sell liquids extracted from natural gas in our storage field and on our pipeline systems. We have three wholly-owned subsidiaries. Delta Resources, Inc. ("Delta Resources") buys natural gas and resells it to industrial or other large use 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 production properties and undeveloped acreage.

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, "2013", "2012" and "2011" refers to the respective twelve month periods ending June 30.

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, transmission 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 minimizing our exposure to market risk arising from fluctuations in the prices of natural gas.

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.

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 industrial 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 as well.

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. Financial Statements and Supplementary Data and under “Regulatory Matters” in Item 1. Business.

Factors that affect our regulated revenues include the rates we charge our customers, economic conditions in our service areas, competition, our supply cost for the natural gas we purchase for resale and weather. Our current rate design lessens the impact weather has on our regulated revenues as our rates include both a fixed monthly customer charge and a volumetric rate which has a weather normalization provision that adjusts rates due to variations in weather. Market risk arising from fluctuations in the price of gas is mitigated through the gas cost recovery rate mechanism which permits us to pass through to our regulated customers changes in the price we must pay for our 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 2013, 73% 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. The Kentucky Public Service Commission, through a weather normalization provision in our tariff, permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

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

Our larger regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the natural gas to their plants or facilities. 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 gas and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most 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 gas supply at competitive market-based rates.

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

As an active participant in many areas of the natural gas industry, we plan to continue efforts to expand our 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.

Gas Supply

We maintain an active 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. In our fiscal year ended June 30, 2013, we purchased approximately 98% of our natural gas from interstate sources.

Interstate Gas Supply

Our regulated segment acquires its interstate gas supply from gas marketers. We currently have commodity requirements agreements with Atmos Energy Marketing (“Atmos”) for our Columbia Gas Transmission Corporation (“Columbia Gas”), Columbia Gulf Transmission Corporation (“Columbia Gulf”), Tennessee Gas Pipeline (“Tennessee”) and Texas Eastern Transmission Corporation (“Texas Eastern”) supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. We are not obligated to purchase any minimum quantities from Atmos or 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 market prices or at mutually agreed-to fixed prices based on forward market prices. The index-based market prices are determined based on the prices published on the first of each month in Platts' Inside FERC's Gas Market Report for the indices that relate to the pipelines through which the gas will be transported, plus or minus an agreed-to fixed price adjustment per million British Thermal Units of gas purchased. Consequently, the price we pay for interstate natural gas is based on current market prices.

Our agreements with Atmos for the Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied service areas continue year to year unless 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, 2013, approximately 61% of our regulated gas supply was purchased under our agreements with Atmos.

Our regulated segment purchases natural gas from M&B Gas Services ("M&B") and 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 either M&B or Midwest, nor are we required to purchase natural gas from either company 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 both M&B and Midwest may be terminated upon 30 days prior written notice by either party. In our fiscal year ended June 30, 2013, approximately 23% and 14% of our regulated gas supply was purchased under our agreements with M&B and Midwest, respectively.

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

Transportation of Interstate Gas Supply

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

Our agreements with Tennessee currently extend through October, 2013 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. We intend to renew our agreements with Tennessee. Subject to the terms of Tennessee's Federal Energy Regulatory Commission gas tariff, Tennessee is obligated under these agreements to transport up to 19,600 thousand cubic feet ("Mcf") per day for us. During fiscal 2013, Tennessee transported for us a total of 884,000 Mcf, or approximately 17% of our regulated supply requirements, under these agreements. We have gas storage agreements with Tennessee under the terms of which we reserve a defined storage space in Tennessee's storage fields and we reserve the right to withdraw daily gas volumes up to certain specified fixed quantities. These gas storage agreements renew on the same schedule as our transportation agreements with Tennessee.

Under our agreements with Columbia Gas and Columbia Gulf, Columbia Gas is obligated to transport, including utilization of our defined storage space as required, up to 12,600 Mcf per day for us, and Columbia Gulf is obligated to transport up to a total of 4,300 Mcf per day for us. During fiscal 2013, Columbia Gas and Columbia Gulf transported for us a total of 2,192,000 Mcf, or approximately 43% of our regulated supply requirements, under all of our agreements with them. Our transportation agreements with Columbia Gas and Columbia Gulf extend through 2015. After 2015, our agreement with Columbia Gas continues on a year-to-year basis unless terminated by one of the parties, but may be extended by mutual agreement.

Columbia Gulf also transported additional volumes under agreements it has with M & B and Midwest to a point of interconnection between Columbia Gulf and us where we purchase the gas to inject into our storage field. The amounts transported and sold to us under the agreements Columbia Gulf has with M & B and Midwest for fiscal 2013 constituted approximately 37% of our regulated gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the gas to us that we purchase from Atmos to supply our customers' requirements in specific geographic areas. In our fiscal year ended June 30, 2013, Texas Eastern transported approximately 13,000 Mcf of natural gas to our system, which constituted less than 1% of our gas supply.

Kentucky Gas Supply

We have an agreement with Vinland Energy Operations LLC ("Vinland") to purchase natural gas on a year-to-year basis unless terminated by one of the parties. We purchased 41,000 Mcf from Vinland during fiscal 2013. The price for the gas we purchase from Vinland is based on the index price of spot gas delivered to Columbia Gas in the relevant region as reported in Platts' Inside FERC's Gas Market Report. Vinland delivers this gas to our customer meters directly from its own pipelines. In fiscal 2013, the natural gas we purchased from Vinland constituted approximately 1% of our regulated gas supply.

Gas in Storage

We own and operate an underground natural gas storage field that we use to store a significant portion of our gas supply needs. This storage capability permits us to purchase and store gas during the non-heating months and then withdraw and sell the gas during the peak usage months. We 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. Their regulation of our business includes approving the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas and transportation services. They have historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of gas costs, and a reasonable rate of return. 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 positions or cash flows.

We have a pipe replacement program which 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.

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

Additionally, we have a weather normalization clause in our rate tariffs, approved by the Kentucky Public Service Commission, which 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.

The Kentucky Public Service Commission also allows us a conservation and efficiency program for our residential customers. 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 margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, 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.

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

In our fiscal year ended June 30, 2013, approximately 96% 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. Seminole Energy provided approximately $17,866,000, $12,450,000 and $11,461,000 of non-regulated revenues during 2013, 2012 and 2011, respectively. Atmos provided approximately $5,390,000, $6,815,000 and $8,067,000 of non-regulated revenues during 2013, 2012 and 2011, 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. Item 2. Properties further describes Enpro's oil and natural gas leases and production properties. Enpro produced a total of 103,000 Mcf of natural gas during 2013 which was approximately 1% of the non-regulated volumes sold.

Natural Gas Liquids

In order 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 sell these natural gas liquids at a price determined by a national unregulated market. In our fiscal year ended June 30, 2013, approximately 4% of our non-regulated revenue was derived from the sale of natural gas liquids.

Gas Supply

Our non-regulated segment purchases natural gas from M&B and Midwest. Our underlying agreements with M&B and Midwest do not obligate us to purchase any minimum quantities from M&B or Midwest, nor to purchase gas from either company for any periods longer than one month at a time. The gas is priced at index-based market prices or at mutually agreed-to fixed prices based on forward market prices. Our agreements with both M&B and Midwest may be terminated upon 30 days prior written notice by either party. Any purchase agreements for unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2013, 50% and 6% of our non-regulated gas supply was purchased under our agreements with M&B and Midwest, respectively.

Additionally, our non-regulated segment purchases natural gas from Atmos as needed. This spot gas purchasing arrangement is pursuant to an agreement with Atmos containing an “evergreen” clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from Atmos under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing gas for one or more months. The price of gas under this agreement is based on current market prices. In our fiscal year ended June 30, 2013, approximately 43% of our non-regulated gas supply was purchased under our agreement with Atmos.

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

We anticipate continuing our non-regulated activities and intend to pursue and increase these activities wherever practicable.

Capital Expenditures

Capital expenditures during 2013 were $7.2 million and for 2014 are estimated to be $7.8 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are met through the use of internally generated funds and a short-term bank line of credit. The current available line of credit is $40 million, all of which was available at June 30, 2013.

Our current bank line of credit extends through June 30, 2015 and will be utilized to meet capital expenditure and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

We currently have long-term debt of $56,500,000 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, 2013, we had 150 full-time employees. We consider our relationship with our employees to be satisfactory. Our employees are not represented by unions nor are they subject to any collective bargaining agreements.

Available Information

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

Consolidated Statistics

For the Years Ended June 30,	2013	2012	2011	2010	2009
Average Regulated Customers Served					
Residential	29,755	29,929	30,420	30,575	30,881
Commercial	4,906	4,890	4,949	4,957	5,009
Industrial	40	41	44	46	49
Total	34,701	34,860	35,413	35,578	35,939
Operating Revenues ($000) (a)					
Regulated (b)					
Residential sales	24,342	22,720	25,800	23,783	33,774
Commercial sales	15,849	14,026	16,672	15,894	24,125
Industrial sales	1,011	914	1,199	1,075	1,769
On-system transportation	5,237	4,780	4,830	4,421	4,118
Off-system transportation	3,800	3,595	3,670	3,650	3,786
Other	333	324	303	294	333
Total regulated revenues	50,572	46,359	52,474	49,117	67,905
Non-regulated sales	34,238	31,423	34,343	30,746	41,159
Intersegment eliminations (c)	(4,145)	(3,704)	(3,777)	(3,441)	(3,427)
Total	80,665	74,078	83,040	76,422	105,637
System Throughput (Million Cu. Ft.) (a)					
Regulated					
Residential sales	1,659	1,331	1,737	1,756	1,721
Commercial sales	1,291	1,027	1,310	1,331	1,346
Industrial sales	107	90	120	111	113
On-system transportation	4,988	4,724	4,830	4,533	4,215
Off-system transportation	11,795	11,225	11,531	11,039	11,908
Total regulated throughput	19,840	18,397	19,528	18,770	19,303
Non-regulated sales	7,650	6,455	6,010	4,787	4,219
Intersegment eliminations (c)	(7,497)	(6,326)	(5,890)	(4,692)	(4,135)
Total	19,993	18,526	19,648	18,865	19,387
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	56	44	57	57	56
Lexington, Kentucky Degree Days					
Actual	4,667	3,797	4,725	4,782	4,651
Percent of 30 year average	104	83	103	104	101

(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) We implemented new regulated base rates, as approved by the Kentucky Public Service Commission in October, 2010, which were designed to generate additional annual revenue of $3,513,000.

(c) Intersegment eliminations represent the natural gas transportation costs from the regulated segment to the non-regulated segment at our tariff rates.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR.

Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 73% of our annual gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell in any year, which would reduce our revenues and profits. The weather normalization provision in our 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.

CHANGES IN FEDERAL REGULATIONS COULD REDUCE THE AVAILABILITY OR INCREASE THE COST OF OUR INTERSTATE GAS SUPPLY.

We purchase almost all of our gas supply from interstate sources. For example, in 2013, approximately 98% of our gas supply was purchased from interstate sources. The Federal Energy Regulatory Commission regulates the transmission of the natural gas we receive from interstate sources, and it could increase our transportation costs or decrease our available pipeline capacity by changing its regulatory policies. Additionally, federal legislation could restrict or limit drilling which could decrease the supply of available natural gas. A decrease in available pipeline capacity or decrease in natural gas available to us could result in a loss of customers and decrease in profits.

OUR GAS SUPPLY DEPENDS UPON THE AVAILABILITY OF ADEQUATE PIPELINE TRANSPORTATION CAPACITY.

We purchase almost all of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation service could reduce our normal interstate supply of gas. A decrease in our normal interstate supply of gas could result in a loss of customers and decrease in profits.

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

Our larger customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the gas to their plants or facilities. Customers 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 by-passes in order to achieve lower prices for their gas and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution and transportation systems creates a risk of the loss of large customers and thus could result in lower revenues and profits.

ACTIONS BY OUR REGULATORS COULD DECREASE FUTURE PROFITABILITY.

We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our operating revenues. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability. Additionally, our consolidated financial statements reflect the application of regulatory accounting standards by our regulated segment. 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 income and consolidated financial statements.

VOLATILITY IN PRICES COULD REDUCE OUR PROFITS.

Significant increases 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 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 unregulated market, and decreases in the price could result in a decrease in our non-regulated gross margins.

INTERSTATE AND OTHER PIPELINES DELTA INTERCONNECTS WITH CAN IMPOSE RESTRICTIONS ON THEIR PIPELINE.

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

FUTURE PROFITABILITY OF THE NON-REGULATED SEGMENT IS DEPENDENT ON A FEW INDUSTRIAL AND OTHER LARGE USE CUSTOMERS.

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

A DECLINE IN THE LIQUIDS PRESENT IN OUR NATURAL GAS SUPPLY COULD REDUCE OUR NON-REGULATED REVENUES.

In order 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 unregulated market. A reduction in the quantity of liquids present in our gas supply 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 price for natural gas, terrorist attacks or the overall health of the energy industry. There is no guarantee we could obtain needed capital in the future.

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

Our cost of providing a non-contributory defined benefit pension plan is dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding 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. Such cash funding obligations 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 cash flows, financial position or results of operations.

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

There are substantial risks associated with the operation of a natural gas distribution, 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, the breakdown or failure of equipment or processes, the performance of pipeline and storage facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage 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 gas distribution, transmission or storage system caused by such an event could reduce our revenues and increase our expenses.

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

Hurricanes, extreme weather or well-head 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. Such events could also result in new governmental regulations or rules that limit production or raise production costs.

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. Noncompliance with these covenants can make the obligations immediately due and payable. 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. In such event, 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 business, results of operations and financial condition. Furthermore, 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. Additionally, our bank line of credit and Series A Notes contain various negative covenants and a prepayment penalty which create a risk that we may be unable to take advantage of business and financing opportunities as they arise.

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

Under the terms of our 4.26% Series A Notes, the aggregate amount we may pay in dividends on our common stock and in repurchase of our common stock may not exceed the sum of $15,000,000 and our cumulative net income after September 30, 2011. Between September 30, 2011 and June 30, 2013, we paid $8,526,000 in dividends, repurchased no stock and have had cumulative net income of $13,318,000. Consequently, as of June 30, 2013 our Series A Notes permitted us to pay up to $19,792,000 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 IT SYSTEMS, INTERRUPT THE NATURAL GAS SERVICE WE PROVIDE TO OUR CUSTOMERS, COMPROMISE THE SAFETY OF OUR NATURAL GAS DISTRIBUTION, TRANSMISSION AND STORAGE SYSTEMS OR EXPOSE CONFIDENTIAL PERSONAL INFORMATION.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to IT 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 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, the protection of customer, employee, vendor, investor and company data is critical to us. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and have a material adverse effect on our reputation, operating results and financial condition. 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 that 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 events, such as an aging workforce, mismatch of skill sets to complement future needs, or unavailability of future resources, may lead to increased operational risks and costs. As a result of these events, we could face lack of resources knowledgeable about the natural gas industry and 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, adoption of International Financial Reporting Standards and tax law, 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, cash flows, results of operations or access to capital.

CLIMATE CHANGE LEGISLATION MAY POSE NEW FINANCIAL OR REGULATORY RISKS.

A number of proposals to limit greenhouse gas emissions are pending at the regional, federal, and international levels. These proposals, if enacted and made applicable to us, may require us to measure and potentially limit greenhouse gas emissions from our utility operations and our customers or purchase allowances for such emissions. While we cannot predict the extent of these limitations or when or if they will become effective, the adoption of such proposals could increase utility costs related to operations, energy efficiency activities and compliance; affect the demand for natural gas; and increase the prices we charge our 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 Delta's results of operations, financial condition and cash flows.

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 2,500 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. Business.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business. Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.7 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others for further drilling and development. We have performed no reserve studies on these properties. Enpro produced a total of 103,000 Mcf of natural gas during fiscal 2013 from all the properties described in this paragraph.

A producer plans to conduct further exploration activities on part of Enpro's developed holdings. Enpro reserves the option to participate in wells drilled by this producer and also retains certain working and royalty interests in any production from future wells.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

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

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.

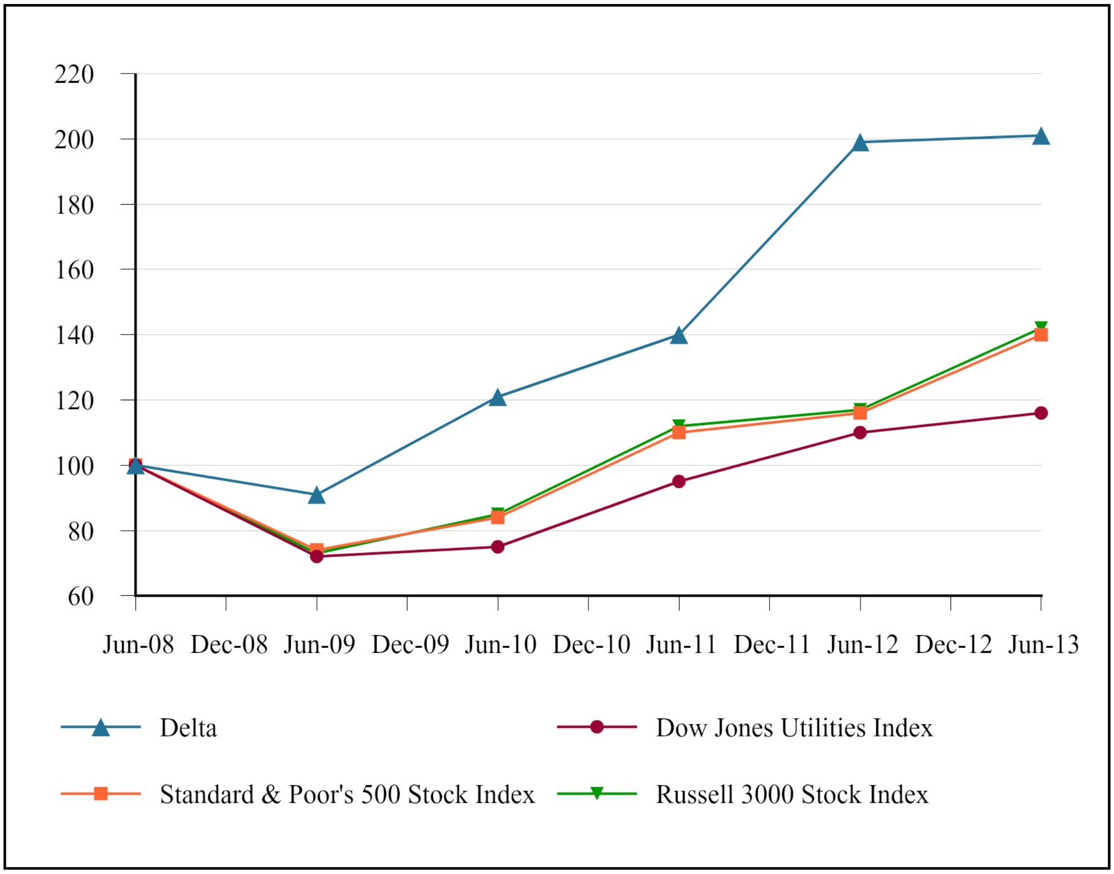
Our common stock is listed on NASDAQ and trades under the symbol "DGAS". There were 1,537 record holders of our common stock as of August 27, 2013. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ stock market and the cash dividends declared per share.

	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2013			
First	24.82	18.41	0.18
Second	22.16	17.08	0.18
Third	22.08	18.88	0.18
Fourth	24.18	19.99	0.18
Fiscal 2012			
First	16.98	14.51	0.175
Second	17.24	14.12	0.175
Third	19.61	16.72	0.175
Fourth	23.15	18.83	0.175

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.

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, the Russell 3000 Stock Index and the Standard & Poor's 500 Stock Index during the past five fiscal years. Information reflected on the graph assumes an investment of $100 on June 30, 2008 in each of our common shares, the Dow Jones Utilities Index, the Russell 3000 Stock Index and the Standard & Poor's 500 Stock Index. Cumulative total return assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.



	2008	2009	2010	2011	2012	2013
Delta	100	91	121	140	199	201
Dow Jones Utilities Index	100	72	75	95	110	116
Standard & Poor's 500 Stock Index	100	74	84	110	116	140
Russell 3000 Stock Index	100	73	85	112	117	142

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,	2013	2012	2011	2010	2009
Summary of Operations ($)					
Operating revenues (a)	80,664,837	74,078,322	83,040,251	76,422,068	105,636,824
Operating income (a)(b)(c)	13,188,679	13,265,228	14,061,794	12,904,494	12,793,200
Net income (a)(b)(c)	7,200,776	5,783,998	6,364,895	5,651,817	5,210,729
Earnings per common share (a)(b)(c)					
Basic and diluted	1.05	0.85	0.95	0.85	0.79
Cash dividends declared per common share	0.72	0.70	0.68	0.65	0.64
Weighted Average Number of Common Shares					
Basic	6,843,455	6,777,186	6,707,224	6,652,320	6,612,052
Diluted	6,843,455	6,777,186	6,712,804	6,652,320	6,612,052
Total Assets ($)	183,930,015	182,895,363	174,896,239	168,632,420	162,505,295
Capitalization ($)					
Common shareholders' equity	70,005,415	66,220,407	63,767,184	60,760,170	58,999,182
Long-term debt	55,000,000	56,500,000	56,751,006	57,112,000	57,599,000
Total capitalization	125,005,415	122,720,407	120,518,190	117,872,170	116,598,182
Short-Term Debt ($) (d)	1,500,000	1,500,000	1,200,000	1,200,000	4,853,103
Other Items ($)					
Capital expenditures	7,179,473	7,337,115	8,123,479	5,275,194	8,422,433
Total property, plant and equipment	223,545,925	217,172,542	211,409,336	204,248,520	199,254,216

(a) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2010 and the rates were designed to generate additional annual revenue of $3,513,000, with a $1,770,000 increase in annual depreciation expense.
(b) We recorded a non-recurring $1,350,000 gas in storage inventory adjustment at December 31, 2008.
(c) In 2012, $877,000 of interest expense was accrued relating to a tax assessment. In 2013, the assessment was resolved and the previously accrued interest was reversed.
(d) Includes current portion of long-term debt.

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

Overview of 2013 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 2013. Our Company has two segments: (i) a regulated natural gas distribution and transmission segment, and (ii) a non-regulated segment which participates in related activities, consisting of natural gas marketing, natural gas production and the sale of liquids extracted from natural gas.

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

Our non-regulated segment markets natural gas to large-use customers both on and off our regulated system. We endeavor to enter sales agreements matching supply with estimated demand while providing an acceptable gross margin. The non-regulated segment also produces natural gas and sells liquids extracted from natural gas.

Consolidated earnings per common share for 2013 increased $0.20 per common share as compared to 2012. We experienced a winter that was significantly colder than the preceding year resulting in increased volumes of natural gas sold as well as increased volumes transported by our regulated segment. Also, decreased interest expense resulting from the resolution of a tax assessment issued to Delta Resources (as further discussed in Note 13 of the Notes to Consolidated Financial Statements) had a positive impact on earnings. Other factors which influenced our 2013 consolidated earnings per common share are further discussed in the Results of Operations.

Future Outlook

Future profitability of the regulated segment is contingent on the adequate and timely adjustment of the rates we charge our regulated customers. The Kentucky Public Service Commission sets these rates, and we monitor our need to file rate cases with the Kentucky Public Service Commission for a general rate increase for our regulated services. The regulated segment's largest expense is 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 use 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 to continue to contribute to our consolidated net income in fiscal 2014. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment margins related to our natural gas production and marketing activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated margins related to our natural gas production and marketing activities. The profitability of selling natural gas liquids is dependent on the amount of liquids extracted and the pricing for any such liquids is determined by a national unregulated market.

Liquidity and Capital Resources

Sources and Uses of Cash

Operating activities provide our primary source of cash. Cash provided by operating activities consists of net income adjusted for non-cash items, including depreciation, amortization, deferred income taxes and changes in working capital. Our sales and cash requirements are seasonal. The largest portion of our sales occurs during the heating months, 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 permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit as of June 30, 2013 or June 30, 2012 and we did not draw on this bank line of credit during 2013.

Cash and cash equivalents were $10,360,000 at June 30, 2013 compared with $9,741,000 at June 30, 2012 and $7,340,000 at June 30, 2011. These changes in cash and cash equivalents are summarized in the following table:

$(000)	2013	2012	2011
Provided by operating activities	13,557	13,514	14,467
Used in investing activities	(7,108)	(7,012)	(7,520)
Used in financing activities	(5,829)	(4,102)	(4,246)
Increase in cash and cash equivalents	620	2,400	2,701

In 2013, there was not a significant change in cash provided by operating activities as compared to 2012.

In 2012, there was not a significant change in cash provided by operating activities as compared to 2011.

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

In 2013, cash used in financing activities increased $1,727,000 (42%), as compared to 2012, due to a $1,500,000 repayment on our 4.26% Series A Notes.

In 2012, there was not a significant change in cash used in financing activities as compared to 2011.

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, storage and general facilities. We expect our capital expenditures for fiscal 2014 to be approximately $7.8 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2013:

	Payments Due by Fiscal Year				
$(000)	2014	2015 - 2016	2017 - 2018	After 2018	Total
Interest payments (a)	2,428	4,554	4,299	22,302	33,583
Long-term debt (b)	1,500	3,000	3,000	49,000	56,500
Pension contributions (c)	500	1,000	1,000	4,500	7,000
Gas purchases (d)	328	—	—	—	328
Total contractual obligations (e)	4,756	8,554	8,299	75,802	97,411

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2013 interest payments until the underlying obligation is satisfied. As of June 30, 2013, we have also accrued $9,000 of interest related to uncertain tax positions. These amounts have been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(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 plan through 2026, as recommended by our actuary.

(d) As of June 30, 2013, we had three contracts which had minimum purchase obligations. These contracts have various terms with the last contract expiring December, 2013. The remainder of our 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 ($39,624,000), regulatory liabilities ($1,253,000), asset retirement obligations ($3,547,000) and deferred compensation ($739,000). 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 sets 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 will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future.

To the extent that internally generated cash is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we rely on our bank line of credit. Our current available bank line of credit with Branch Banking and Trust Company extends through June 30, 2015 and permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit during 2013 as we did not draw upon this bank line of credit during 2013.

In December, 2011, we refinanced our 5.75% Insured Quarterly Notes and 7% Debentures from the proceeds of a private debt financing. Under the Note Purchase and Private Shelf Agreement, we issued $58,000,000 of Series A Notes, for which the purchasers paid 100% of the face principal amount. The proceeds from the sale of the Series A Notes were used to fund the redemption of our 5.75% Insured Quarterly Notes Due April 1, 2021, which had an outstanding principal balance of $38,450,000, and our 7% Debentures Due February 1, 2023, which had an outstanding principal balance of $19,410,000.

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.

The Agreement for the Series A Notes contains a private shelf facility that extends through December, 2013. We may, with mutual agreement between us and the purchasers or their affiliates, issue them additional long-term unsecured promissory notes of the Company in an aggregate principal amount up to $17,000,000.

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 obligation 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, 2013:

	Requirement	Actual
Tangible net worth	no less than $25,800,000	$68,674,245
Debt to capitalization ratio	no more than 70%	45%
Fixed charge coverage ratio	no less than 1.20x	7.75 x
Dividends paid	no more than $28,318,000	$ 8,526,000

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 rate-making 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 of regulatory accounting, that segment will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of 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.

Pension

We have a trusteed, non-contributory, defined benefit pension plan covering all eligible employees hired prior to May 9, 2008. The net periodic benefit costs ("pension costs") for our defined benefit 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, 2013, 2012 and 2011, we recorded pension costs for our defined benefit pension plan of $980,000, $481,000 and $1,129,000, 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 in the future over the average remaining service period of active plan participants. As of June 30, 2013, $6,369,000 of net losses have been deferred for amortization as pension costs into future periods.

Our pension plan assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns will 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 pension plan assets was 7% for 2013 and was based on our targeted asset allocation assumption for 2013 of approximately 70% equity investments and approximately 30% fixed income investments. Our target investment allocation for equity investments includes allocations to domestic, global and real estate markets. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

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 6%, discount rate of 4.5%, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plan will decrease from $980,000 in 2013 to $750,000 in 2014. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2014 by approximately $65,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $82,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $86,000.

Provisions for Doubtful Accounts

We encounter risks associated with the collection of our accounts receivable. As such, we record a monthly provision for accounts receivable that are considered to be uncollectible. In our regulated segment, the risk of non-collection on accounts receivable is partially mitigated by our ability to recover the portion of bad debt expense that relates to the customers' gas cost through our gas cost recovery mechanism.

In order to calculate the appropriate monthly provision, we primarily utilize our historical experience related to accounts written-off. Quarterly, at a minimum, we review the reserve for reasonableness based on the level of revenue and the aging of the receivable balance. Additionally, we specifically review significant account balances for collectibility. The underlying assumptions used for the allowance can change from period to period and the allowance could potentially cause a material impact to the Consolidated Statements of Income. The actual weather, commodity prices and other internal and external economic conditions, such as the mix of the customer base between residential, commercial and industrial, may vary significantly from our assumptions and may impact operating income.

Unbilled Revenues and Gas Costs

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

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations is recorded at the time the obligations are incurred. We do not recognize asset retirement obligations relating to assets with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities accrete for the change in their present value, and the initial capitalized costs depreciate over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the accretion and depreciation are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement date and the assumed credit-adjusted risk-free interest rate. Our asset retirement obligations are further discussed in Note 4 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as “estimates”, “attempts”, “expects”, “monitors”, “plans”, “anticipates”, “intends”, “continues”, “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,
- pension plan costs and management,
- contractual obligations and cash requirements,
- management of our gas supply and risks due to potential fluctuation in the price of natural gas,
- revenues, income, margins and profitability,
- efforts to purchase and transport locally produced natural gas,
- recovery of regulatory assets,
- 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. Risk Factors 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 of natural gas and the provision of natural gas transportation services. We define “gross margins” as gas sales less the corresponding purchased gas expenses, plus transportation, natural gas liquids and other revenues. 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. Gross margin can be derived directly from our Consolidated Statements of Income as follows:

($000)	2013	2012	2011
Operating revenues (a)	80,665	74,078	83,040
Regulated purchased gas (a)	(17,825)	(15,703)	(21,077)
Non-regulated purchased gas (a)	(26,011)	(23,380)	(26,762)
Consolidated gross margins	36,829	34,995	35,201

(a) amounts from the Consolidated Statements of Income included in Item 8. Financial Statements and Supplemental Data

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

In the following table we set forth variations in our gross margins for the last two 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)	2013 compared to 2012	2012 compared to 2011
Increase (decrease) in gross margins		
Regulated segment		
Natural gas sales	1,420	(641)
On-system transportation	457	(50)
Off-system transportation	205	(75)
Other	9	25
Intersegment elimination (a)	(441)	73
Total	1,650	(668)
Non-regulated segment		
Natural gas sales	(256)	(784)
Natural gas liquids	41	1,360
Other	(42)	(41)
Intersegment elimination (a)	441	(73)
Total	184	462
Increase (decrease) in consolidated gross margins	1,834	(206)
Percentage increase (decrease) in volumes		
Regulated segment		
Natural gas sales (Mcf)	25	(23)
On-system transportation (Mcf)	6	(2)
Off-system transportation (Mcf)	5	(3)
Non-regulated segment		
Natural gas sales (Mcf)	19	7
Natural gas liquids (gallons)	34	100

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

Heating degree days were 104% of normal thirty year average temperatures for fiscal 2013, as compared with 83% and 103% of normal temperatures for 2012 and 2011, respectively. 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. A heating degree day is the equivalent for each degree that the average of the high and the low temperatures for a day is below 65 degrees in a specific geographic location. Normal degree days are based on the historical thirty year average National Weather Service data for the same geographic location.

In 2013, consolidated gross margins increased $1,834,000 (5%), as compared to 2012, due to increased regulated and non-regulated gross margins of $1,650,000 and $184,000, respectively. Regulated gross margins increased due to a 25% increase in volumes sold to our regulated customers as a result of colder weather and an increase in volumes transported as a result of an increase in our transportation customers' gas requirements. Partially offsetting these increases are decreased rates billed through our weather normalization tariff.

In 2012, consolidated gross margins decreased $206,000 (1%), as compared to 2011, due to decreased regulated gross margins of $668,000 (2%) partially offset by increased non-regulated gross margins of $462,000 (6%). Regulated gross margins decreased due to a 23% decline in volumes sold as a result of warmer weather as compared to 2011. Partially offsetting this decrease are increased rates billed through our weather normalization tariff. Non-regulated gross margins increased due to the sale of liquids extracted from natural gas, as we completed the installation of a facility to extract liquids from the natural gas in our system in order to improve the operations of our distribution, transmission and storage systems. The increase was partially offset by decreases in gross margins from non-regulated natural gas sales due to a decline in sales prices.

Operation and Maintenance

In 2013, operation and maintenance increased $1,556,000 (11%) due to a $1,230,000 increase in labor and employee benefits resulting from an increase in pension expense and share-based compensation and a $369,000 increase in uncollectible expense.

In 2012, there were no significant changes in operation and maintenance, as compared to 2011.

Depreciation and Amortization

In 2013, there were no significant changes in depreciation and amortization, as compared to 2012.

In 2012, depreciation and amortization increased $767,000 (15%), as compared to 2011, due to increased depreciation rates approved by the Kentucky Public Service Commission in October 2010 as part of our 2010 rate case, and increased depreciable plant.

Taxes Other Than Income Taxes

In 2013, there were no significant changes in taxes other than income taxes, as compared to 2012.

In 2012, taxes other than income taxes increased $238,000 (12%), as compared to 2011, due to increased property tax expense resulting from both higher assessed values and rates assessed by taxing jurisdictions.

Interest on Long-Term Debt

In 2013 and 2012, interest on long-term debt decreased $546,000 (18%) and $601,000 (17%), respectively, as a result of refinancing our 5.75% Insured Quarterly Notes and 7% Debentures (as further discussed in Note 10 of the Notes to Consolidated Financial Statements).

Other Interest (Income) Expense

In 2013, other interest (income) expense decreased $1,807,000 (183%) due to a decrease in interest accrued for a tax assessment issued to Delta Resources by the Kentucky Department of Revenue (as further discussed in Note 13 of the Notes to Consolidated Financial Statements).

In 2012, other interest (income) expense increased $868,000 (742%) due to interest accrued relating to a tax assessment issued to Delta Resources by the Kentucky Department of Revenue (as further discussed in Note 13 of the Notes to Consolidated Financial Statements).

Income Tax Expense

In 2013, income tax expense increased $1,011,000 (31%) due to an increase in net income before income taxes. There were no significant changes in our effective tax rate for 2013, as compared to 2012.

In 2012, income tax expense decreased $502,000 (13%), as compared to 2011, due to a decrease in net income before income taxes. There were no significant changes in our effective tax rate for 2012, as compared to 2011.

Basic and Diluted Earnings Per Common Share

For 2013 and 2012, our basic and diluted earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our dividend reinvestment and stock purchase plan 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.

Under our Incentive Compensation Plan, recipients of performance share awards receive unvested non-participating shares, as further discussed in Note 17 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. 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.

Certain unvested awards under our shareholder approved incentive compensation plan, as further discussed in Note 17 of the Notes to Consolidated Financial Statements, provide the recipients of the awards all the rights of a shareholder of Delta Natural Gas Company, Inc. including a 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. There were 68,000 and 48,000 unvested participating shares outstanding as of June 30, 2013 and 2012, respectively. There were no antidilutive shares in 2013 and 2012.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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

None of our gas contracts are accounted for using the fair value method of accounting. While some of our gas purchase and gas sales contracts meet the definition of a derivative, we have designated these contracts as normal purchases and normal sales. As of June 30, 2013, we had forward purchase contracts totaling $328,000 that have various terms with the last contract expiring in December, 2013. These forward purchase contracts 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, 2013 or June 30, 2012. The weighted average interest rate on our bank line of credit was 1.3% and 1.4% as of June 30, 2013 and June 30, 2012, respectively. We did not have any borrowings on our bank line of credit during 2013.

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

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2013 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, 2013 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, 2013 based on the framework in *Internal Control - Integrated Framework* issued in 1992 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, 2013.

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.:

We have audited the internal control over financial reporting of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013 of the Company and our report dated August 27, 2013 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 27, 2013

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 can be found on our website by going to the following address: http://www.deltagas.com. We will post any amendments to the Business Code of Conduct and Ethics, as well as any waivers that are required to be disclosed by the rules of either the Securities and Exchange Commission or the NASDAQ OMX Group, on our website.

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

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 2013 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2013. 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 2013 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2013. 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, 2013:

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)
—	—	849,790

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 2013 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2013. 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 2013 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2013. 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 2013 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2013. We incorporate that information in this document by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements
See Index at Item 8

(2) Financial Statement Schedules
See Index at Item 8

(3) Exhibits

Exhibit No.	
3.1	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 20, 2013) are incorporated herein by reference to Exhibit 3.1 to Registrant's Form 8-K (File No. 000-8788) dated August 21, 2013.
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	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.
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	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.
10.04	Gas Sales Agreement, dated May 1, 2010, by and between Atmos Energy Marketing, LLC and Registrant is 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.
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 is filed herewith.
10.06	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 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 November 1, 1993 (Service Agreement Nos. 37,813, 37,814 and 37,815), and Appendix A to respective Service Agreements, effective November 1, 2010, by and between Columbia Gas Transmission Corporation and Registrant incorporated herein by reference to Exhibit 10(g) to Registrant's Form 10-K (File No. 000-08788), for the period ended June 30, 2010.
10.10	FTS1 Service Agreements, dated October 4, 1994, (Service Agreement Nos. 43,827, 43,828 and 43,829), and Appendix A to respective Service Agreements, effective November 1, 2010, by and between Columbia Gulf Transmission Corporation and Registrant incorporated herein by reference to Exhibit 10(h) to Registrant's Form 10-K (File No. 000-08788), for the period ended June 30, 2010.
10.11	Underground Gas Storage Lease and Agreement, dated March 9, 1994, by and between Equitable Resources Exploration, a division of Equitable Resources Energy Company, and Lonnie D. Ferrin and Amendment No. 1 and Novation to Underground Gas Storage Lease and Agreement, dated March 22, 1995, by and between Equitable Resources Exploration, Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(m) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.

10.12	Oil and Gas Lease, dated July 19, 1995, by and between Meredith J. Evans and Helen Evans and Paddock Oil and Gas, Inc.; Assignment, dated June 15, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; Assignment, dated August 31, 1995, by Paddock Oil and Gas, Inc., as assignor, to Lonnie D. Ferrin, as assignee; and Assignment and Assumption Agreement, dated November 10, 1995, by and between Lonnie D. Ferrin and Registrant, is incorporated herein by reference to Exhibit 10(o) to Registrant's Form S-2 (Reg. No. 333-104301) dated April 4, 2003.
10.13	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	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 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	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.
10.26	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.
10.27	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.
10.28	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.

10.29	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.
10.30	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.
10.31	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.
10.32	Notices of Performance Shares Award between four officers, those being John B. Brown, Johnny L. Caudill, Glenn R. Jennings, and Brian S. Ramsey, and Registrant, are incorporated herein by reference to Exhibits 10.3, 10.4, 10.5 and 10.6 of Registrant's Form 8-K (File No. 000-08788) dated August 20, 2010.
10.33	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 Exhibits 10.1, 10.2, 10.3, 10.4 and 10.5 of Registrant's Form 8-K (File No. 000-08788) dated August 16, 2011.
10.34	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 of Registrant's Form 8-K (File No. 000-08788) dated August 21, 2012.
10.35	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 of Registrant's Form 8-K (File No. 000-08788) dated August 21, 2013.
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.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Database
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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, 2013, 2012 and 2011;

(iii) Consolidated Statements of Cash Flows for the years ended June 30, 2013, 2012 and 2011;

(iv) Consolidated Balance Sheets as of June 30, 2013 and 2012;

(v) Consolidated Statements of Changes in Shareholders' Equity for the years ended June 30, 2013, 2012 and 2011;

(vi) Notes to Consolidated Financial Statements;

(vii) Schedule II – Valuation and Qualifying Accounts for the years ended June 30, 2013, 2012 and 2011.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospects for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

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 27th day of August, 2013.

DELTA NATURAL GAS COMPANY, INC.

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

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 27, 2013

(ii) Principal Financial Officer:

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 27, 2013

(iii) Principal Accounting Officer:

/s/Matthew D. Wesolosky (Matthew D. Wesolosky)	Vice President - Controller	August 27, 2013

(iv) A Majority of the Board of Directors:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 27, 2013
/s/Sandra C. Gray (Sandra C. Gray)	Director	August 27, 2013
/s/Edward J. Holmes (Edward J. Holmes)	Director	August 27, 2013
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 27, 2013
/s/Lewis N. Melton (Lewis N. Melton)	Director	August 27, 2013
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 27, 2013
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Delta Natural Gas Company, Inc. and subsidiaries (the "Company") as of June 30, 2013 and 2012, 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, 2013. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Delta Natural Gas Company, Inc. and subsidiaries as of June 30, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2013, 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, present fairly, in all material respects, the information set forth therein.

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, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated August 27, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 27, 2013

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Year Ended June 30,	2013	2012	2011
Operating Revenues			
Regulated revenues	$ 46,427,203	$ 42,655,378	$ 48,697,530
Non-regulated revenues	34,237,634	31,422,944	34,342,721
Total operating revenues	$ 80,664,837	$ 74,078,322	$ 83,040,251
Operating Expenses			
Regulated purchased gas	$ 17,825,487	$ 15,703,114	$ 21,077,548
Non-regulated purchased gas	26,011,164	23,380,426	26,761,726
Operation and maintenance	15,208,162	13,651,689	14,065,725
Depreciation and amortization	6,092,651	5,923,775	5,156,973
Taxes other than income taxes	2,338,694	2,154,090	1,916,485
Total operating expenses	$ 67,476,158	$ 60,813,094	$ 68,978,457
Operating Income	$ 13,188,679	$ 13,265,228	$ 14,061,794
Other Income and Deductions, Net	$ 150,816	$ 75,170	$ 151,506
Interest Charges			
Interest on long-term debt	$ 2,438,325	$ 2,984,413	$ 3,584,772
Other interest (income) expense	(822,190)	984,612	116,763
Amortization of debt expense	253,800	329,231	387,263
Total interest charges	$ 1,869,935	$ 4,298,256	$ 4,088,798
Net Income Before Income Taxes	$ 11,469,560	$ 9,042,142	$ 10,124,502
Income Tax Expense	$ 4,268,784	$ 3,258,144	$ 3,759,607
Net Income	$ 7,200,776	$ 5,783,998	$ 6,364,895
Earnings Per Common Share (Note 11)			
Basic	$ 1.05	$ 0.85	$ 0.95
Diluted	$ 1.05	$ 0.85	$ 0.95
Dividends Declared Per Common Share	$ 0.72	$ 0.70	$ 0.68

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,	2013	2012	2011
Cash Flows From Operating Activities			
Net income	$ 7,200,776	$ 5,783,998	$ 6,364,895
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	6,428,051	6,334,647	5,640,916
Deferred income taxes and investment tax credits	1,959,741	2,513,400	2,536,234
Change in cash surrender value of officer's life insurance	(27,300)	153	(58,744)
Share-based compensation	921,709	712,144	526,859
Excess tax deficiency from share-based compensation	(8,946)	—	—
(Increase) decrease in assets			
Accounts receivable	(841,574)	(1,407,711)	(1,833,298)
Gas in storage	1,451,494	(121,547)	(605,529)
Deferred gas cost	(536,552)	(7,581)	(81,799)
Materials and supplies	9,256	(51,724)	20,629
Prepayments	893,490	(2,606,809)	1,874,828
Other assets	(177,919)	(548,470)	(34,260)
Increase (decrease) in liabilities			
Accounts payable	2,725,470	(3,518,540)	1,936,487
Accrued taxes	(2,757,561)	2,695,526	122,358
Asset retirement obligations	(493,946)	1,085,920	(1,351,841)
Other liabilities	(3,189,770)	2,650,640	(591,014)
Net cash provided by operating activities	$ 13,556,419	$ 13,514,046	$ 14,466,721
Cash Flows From Investing Activities			
Capital expenditures	$ (7,179,473)	$ (7,337,115)	$ (8,123,479)
Proceeds from sale of property, plant and equipment	131,545	183,678	171,641
Other	(60,000)	141,530	431,897
Net cash used in investing activities	$ (7,107,928)	$ (7,011,907)	$ (7,519,941)

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,	2013	2012	2011
Cash Flows From Financing Activities			
Dividends on common shares	$ (4,951,002)	$ (4,762,257)	$ (4,562,284)
Issuance of common shares	587,359	697,775	677,544
Debt issuance costs	—	(107,904)	—
Issuance of long-term debt	—	58,000,000	—
Excess tax benefit from share-based compensation	35,112	21,563	—
Repayment of long-term debt	(1,500,000)	(57,951,006)	(360,993)
Borrowings on bank line of credit	—	17,697,829	17,824,196
Repayment of bank line of credit	—	(17,697,829)	(17,824,196)
Net cash used in financing activities	$ (5,828,531)	$ (4,101,829)	$ (4,245,733)
Net Increase in Cash and Cash Equivalents	$ 619,960	$ 2,400,310	$ 2,701,047
Cash and Cash Equivalents, Beginning of Year	9,740,502	7,340,192	4,639,145
Cash and Cash Equivalents, End of Year	$ 10,360,462	$ 9,740,502	$ 7,340,192
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	$ 2,509,962	$ 3,795,590	$ 3,702,692
Income taxes (net of refunds)	$ 1,573,321	$ 1,011,138	$ (124,861)
Significant non-cash transactions			
Accrued capital expenditures	$ 301,679	$ 336,543	$ 340,670
Loss on extinguishment of debt recognized as a regulatory asset (Note 10)	$ —	$ 1,896,000	$ —

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,	2013	2012
Assets		
Current Assets		
Cash and cash equivalents	$ 10,360,462	$ 9,740,502
Accounts receivable, less accumulated allowances for doubtful accounts of $536,000 and $157,000 in 2013 and 2012, respectively	8,700,982	8,028,937
Gas in storage, at average cost (Notes 1 and 16)	5,481,313	6,932,807
Deferred gas costs (Notes 1 and 14)	3,922,844	3,386,292
Materials and supplies, at average cost	561,270	557,118
Prepayments	1,987,855	2,393,674
Total current assets	$ 31,014,726	$ 31,039,330
Property, Plant and Equipment	$ 223,545,925	$ 217,172,542
Less - Accumulated provision for depreciation	(88,429,625)	(82,835,542)
Net property, plant and equipment	$ 135,116,300	$ 134,337,000
Other Assets		
Cash surrender value of life insurance (face amount of $945,000 and $941,000 in 2013 and 2012, respectively)	$ 334,425	$ 307,125
Prepaid Pension (Note 6)	2,679,864	—
Regulatory assets (Note 1)	13,770,011	16,517,812
Unamortized debt expense (Notes 1 and 10)	97,104	104,104
Other non-current assets	917,585	589,992
Total other assets	$ 17,798,989	$ 17,519,033
Total assets	$ 183,930,015	$ 182,895,363

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,	2013	2012
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 7,417,789	$ 4,325,653
Current portion of long-term debt (Note 10)	1,500,000	1,500,000
Accrued taxes	1,433,666	4,154,064
Customers' deposits	646,375	853,061
Accrued interest on debt	132,560	1,026,387
Accrued vacation	730,867	736,856
Deferred income taxes	1,339,287	1,130,581
Other liabilities	435,064	436,281
Total current liabilities	$ 13,635,608	$ 14,162,883
Long-Term Debt (Note 10)	$ 55,000,000	$ 56,500,000
Long-Term Liabilities		
Deferred income taxes	$ 39,623,563	$ 37,732,457
Investment tax credits	40,600	62,700
Regulatory liabilities (Note 1)	1,252,629	1,380,838
Accrued pension	—	2,307,260
Asset retirement obligations (Note 4)	3,547,441	3,823,724
Other long-term liabilities	824,759	705,094
Total long-term liabilities	$ 45,288,992	$ 46,012,073
Commitments and Contingencies (Note 13)		
Total liabilities	$ 113,924,600	$ 116,674,956
Shareholders' Equity		
Common shares ($1.00 par value), 20,000,000 shares authorized; 6,864,253 and 6,803,941 shares outstanding at June 30, 2013 and June 30, 2012, respectively	$ 6,864,253	$ 6,803,941
Premium on common shares	45,523,123	44,048,201
Retained earnings	17,618,039	15,368,265
Total shareholders' equity	$ 70,005,415	$ 66,220,407
Total liabilities and shareholders' equity	$ 183,930,015	$ 182,895,363

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, 2013			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,803,941	$ 44,048,201	$ 15,368,265	$ 66,220,407
Net income	—	—	$ 7,200,776	7,200,776
Issuance of common shares	28,436	558,923	—	587,359
Issuance of common shares under the incentive compensation plan	31,876	232,226	—	264,102
Share-based compensation expense	—	657,607	—	657,607
Tax benefit from share-based compensation	—	26,166	—	26,166
Dividends on common shares	—	—	(4,951,002)	(4,951,002)
Balance, end of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415

	Year Ended June 30, 2012			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,732,344	$ 42,688,316	$ 14,346,524	$ 63,767,184
Net income	—	—	5,783,998	5,783,998
Issuance of common shares	38,929	658,846	—	697,775
Issuance of common shares under the incentive compensation plan	32,668	304,373	—	337,041
Share-based compensation expense	—	375,103	—	375,103
Tax benefit from share-based compensation	—	21,563	—	21,563
Dividends on common shares	—	—	(4,762,257)	(4,762,257)
Balance, end of year	$ 6,803,941	$ 44,048,201	$ 15,368,265	$ 66,220,407

	Year Ended June 30, 2011			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,669,712	$ 41,546,545	$ 12,543,913	$ 60,760,170
Net income	—	—	6,364,895	6,364,895
Issuance of common shares	44,632	632,912	—	677,544
Issuance of common shares under the incentive compensation plan	18,000	245,970	—	263,970
Share-based compensation expense	—	262,889	—	262,889
Dividends on common shares	—	—	(4,562,284)	(4,562,284)
Balance, end of year	$ 6,732,344	$ 42,688,316	$ 14,346,524	$ 63,767,184

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Principles of Consolidation Delta Natural Gas Company, Inc. (“Delta” or “the Company”) distributes or transports natural gas to approximately 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 gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system and sell liquids extracted from natural gas in our storage field and our pipeline systems. We have three wholly-owned subsidiaries. Delta Resources, Inc. ("Delta Resources") buys gas and resells it to industrial or other large use customers on Delta's system. Delgasco, Inc. buys gas and resells it to Delta Resources, Inc. and to customers not on Delta's system. Enpro, Inc. owns and operates production properties and undeveloped acreage. All subsidiaries of Delta are included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

(b) 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.

(c) 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.

(d) Property, Plant and Equipment Property, plant and equipment is stated at original cost, which includes materials, labor, labor related costs and an allocation of general and administrative costs. 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)	2013	2012
Regulated segment		
Distribution, transmission and storage	197,251	192,107
General, miscellaneous and intangibles	22,009	21,963
Construction work in progress	1,711	724
Total regulated segment	220,971	214,794
Non-regulated segment	2,575	2,379
Total property, plant and equipment	223,546	217,173

We have a pipe replacement program approved by the Kentucky Public Service Commission, which allows us to adjust rates annually to earn a return on capital expenditures for the replacement of pipe and related facilities incurred subsequent to the test year in our most recent rate case. The pipe replacement program is designed to additionally recover the costs associated with the mandatory retirement or relocation of facilities.

(e) Depreciation We determine the provision for depreciation using the straight-line method and by the application of rates to various classes of utility plant. The rates are based upon the estimated service lives of the properties and were equivalent to composite rates of 2.9%, 2.9% and 2.6% of average depreciable plant for 2013, 2012 and 2011, respectively. Effective October, 2010 we implemented new depreciation rates approved by the Kentucky Public Service Commission in our 2010 rate case which decreased the remaining depreciable lives of our depreciable assets.

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 Sheet. When depreciable utility plant and equipment is retired any related removal costs incurred are charged against the regulatory liability.

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

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

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

Unbilled revenues and gas costs include the following:

(000)	2013	2012
Unbilled revenues ($)	1,435	1,358
Unbilled gas costs ($)	390	392
Unbilled volumes (Mcf)	47	46

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

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

(j) Revenues and Accounts Receivable Revenues and accounts receivable arise primarily from sales of natural gas to customers and from transportation services for others. Provisions for doubtful accounts are recorded to reflect the expected net realizable value of accounts receivable. Accounts receivable are charged off when deemed to be uncollectible or when turned over to a collection agency to pursue.

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

($000)	2013	2012
Regulatory assets		
Current assets		
Deferred gas costs	3,923	3,386
Other assets		
Conservation/efficiency program expenses	198	236
Loss on extinguishment of debt	3,389	3,636
Asset retirement obligations	3,788	3,001
Accrued pension	6,369	9,537
Regulatory case expenses	26	108
Total other assets	13,770	16,518
Total regulatory assets	17,693	19,904
Regulatory liabilities		
Long-term liabilities		
Accrued cost of removal on long-lived assets	328	338
Regulatory liability for deferred income taxes	925	1,043
Total regulatory liabilities	1,253	1,381

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 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 regulatory assets not earning a return is 21 years.

(l) Impairment of Long-Lived Assets We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. In the opinion of management, our long-lived assets are appropriately valued in the accompanying consolidated financial statements. There were no impairments of long-lived assets during 2013, 2012 or 2011.

(m) 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.

(n) 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 fully fund the related deferred compensation liability.

The assets of the trust consist of 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.

(o) 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.

(p) 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 gas escaping from the field. We periodically analyze the volumes, pressure and other data relating to the storage field in order to substantiate the gas inventory carried in our perpetual inventory records. 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 gas in storage inventory is recorded at average cost.

(2) New Accounting Pronouncements

In May, 2011, the Financial Accounting Standards Board issued guidance on fair value measurement and disclosure. The guidance was issued as part of a joint effort between the Financial Accounting Standards Board and the International Accounting Standards Board to converge the two sets of standards into a single conceptual framework which would change how fair value measurement guidance is applied in future periods. The guidance, which was adopted as of March 31, 2012, did not have a material impact on our results of operations, financial position or cash flows.

In December, 2011, the Financial Accounting Standards Board issued guidance requiring additional disclosure of the effect or potential effect of rights of setoff associated with an entity's financial instruments and derivative instruments. The guidance will be effective for our quarter ending September 30, 2013 and is not expected to have a have a material impact on our results of operations, financial position or cash flows.

(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 are recorded at fair value and consist of exchange traded mutual funds. The mutual funds are recorded at fair value using observable market prices from active markets, which are categorized as Level 1 in the fair value hierarchy. The fair value of the trust assets are as follows:

($000)	2013	2012
Trust assets		
Money market	9	6
U.S. equity securities	486	364
U.S. fixed income securities	244	220
	739	590

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. 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 2 in the fair value hierarchy.

	2013		2012	
($000)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
4.26% Series A Notes	56,500	55,150	58,000	59,027

(4) Asset Retirement Obligations

Legal obligations

As of June 30, 2013 and 2012, we have accrued liabilities and related assets, net of accumulated depreciation, relative to the legal obligation to retire certain gas wells, storage tanks, mains and services. In 2012, our asset retirement obligations increased to reflect revisions to the estimated cost to retire certain 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 as asset retirement obligations on the accompanying Consolidated Balance Sheets:

($000)	2013	2012
Balance, beginning of year	3,824	2,561
Liabilities incurred	20	16
Liabilities settled	(616)	(552)
Accretion	267	207
Revisions in estimated cash flows	52	1,592
Balance, end of year	3,547	3,824

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 our regulator even though such costs do not represent legal obligations. In accordance with regulatory accounting standards, $328,000 and $338,000 of such accrued cost of removal was recorded as a regulatory liability on the accompanying Consolidated Balance Sheets as of June 30, 2013 and 2012, 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 recognition of purchased gas costs and certain accruals which are not currently deductible for income tax purposes. Investment tax credits were deferred for certain periods prior to fiscal 1987 and are being amortized to income over the estimated useful lives of the applicable properties. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The current portion of the net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in long-term liabilities 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)	2013	2012
Deferred Tax Liabilities		
Current		
Deferred gas cost	(1,459)	(1,170)
Prepaid expenses	(304)	(319)
	(1,763)	(1,489)
Non-Current		
Accelerated depreciation	(36,004)	(34,955)
Other	(1,040)	(1,077)
Pension	(908)	—
Regulatory assets - asset retirement obligations	(736)	(640)
Regulatory assets - loss on extinguishment of debt	(1,287)	(1,380)
Regulatory assets - unrecognized accrued pension	(2,418)	(3,620)
Regulatory liabilities	(1,268)	(1,268)
	(43,661)	(42,940)
Total deferred tax liabilities	(45,424)	(44,429)
Deferred Tax Assets		
Current		
Accrued employee benefits	313	238
Bad debt reserve	58	57
Other	53	63
	424	358
Non-Current		
Accrued employee benefits	855	653
Asset retirement obligations	1,284	1,389
Investment tax credits	25	38
Other	81	505
Pension	—	886
Regulatory liabilities	1,610	1,650
Section 263 (a) capitalized costs	182	87
	4,037	5,208
Total deferred tax assets	4,461	5,566
Net accumulated deferred income tax liability	(40,963)	(38,863)

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

($000)	2013	2012	2011
Current			
Federal	1,940	525	956
State	390	220	276
Total	2,330	745	1,232
Deferred	1,939	2,513	2,528
Income tax expense	4,269	3,258	3,760

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

(%)	2013	2012	2011
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	(0.2)	(0.3)	(0.3)
Other differences, net	(0.6)	(1.7)	(0.6)
Effective income tax rate	37.2	36.0	37.1

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.

The amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $31,000 and $38,000 as of June 30, 2013 and 2012, respectively. As of June 30, 2013, we have accrued interest of $9,000 on unrecognized tax positions. We recognized interest income of $1,000 on unrecognized tax positions in the 2013 Consolidated Statements of Income. We accrued $3,000 of interest in the 2012 Consolidated Statements of Income.

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

($000)	2013	2012
Balance, beginning of year	200	266
Gross increases - tax positions in prior period	—	131
Gross decreases - tax positions in prior period	(99)	(197)
Balance, end of year	101	200

We file income tax returns in the federal and Kentucky jurisdictions. Tax years previous to June 30, 2011 and June 30, 2010 are no longer subject to examination for federal and Kentucky income taxes, respectively.

(6) Employee Benefit Plans

(a) 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 equal to the amounts necessary to fund the plan adequately.

Generally accepted accounting principles ("GAAP") require employers who sponsor defined benefit plans to recognize the funded status of a defined benefit pension 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 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, 2013 and June 30, 2012, respectively, are as follows:

($000)	2013	2012
Change in Benefit Obligation		
Benefit obligation at beginning of year	23,278	17,915
Service cost	1,116	921
Interest cost	913	921
Actuarial (gain)/loss	(1,271)	3,994
Benefits paid	(515)	(473)
Benefit obligation at end of year	23,521	23,278
Change in Plan Assets		
Fair value of plan assets at beginning of year	20,971	21,056
Actual return on plan assets	2,945	(112)
Employer contributions	2,800	500
Benefits paid	(515)	(473)
Fair value of plan assets at end of year	26,201	20,971
Recognized Amounts		
Projected benefit obligation	(23,521)	(23,278)
Plan assets at fair value	26,201	20,971
Funded status	2,680	(2,307)
Net amount recognized as prepaid (accrued) benefit costs on the Consolidated Balance Sheets	2,680	(2,307)
Items Not Yet Recognized as a Component of Net Periodic Benefit Costs		
Prior service cost	(403)	(489)
Net loss	6,772	10,026
Amounts recognized as regulatory assets	6,369	9,537

The accumulated benefit obligation was $20,508,000 and $20,125,000 for 2013 and 2012, respectively.

($000)	2013	2012	2011
Components of Net Periodic Benefit Cost			
Service cost	1,116	921	939
Interest cost	913	921	854
Expected return on plan assets	(1,578)	(1,474)	(1,079)
Amortization of unrecognized net loss	615	200	501
Amortization of prior service cost	(86)	(87)	(86)
Net periodic benefit cost	980	481	1,129
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	4.5	4.0	5.25
Rate of compensation increase	4.0	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	4.0	5.25	5.25
Expected long-term return on plan assets	7.0	7.0	7.0
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 70% equity investments and 30% fixed income investments. Our equity investment target allocations are heavily weighted toward domestic equity securities, with allocations to domestic real estate securities, inflation indexed securities and foreign equity securities for the purposes of diversification. Fixed income securities primarily include U.S. government obligations and corporate debt securities. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

The assets of the plan are comprised of investments in mutual funds. In June, 2013, upon changing investment advisors for our defined benefit plan, we adopted a new asset allocation model which resulted in changes to our target allocation for plan assets and the reallocation of our investment in the common collective trusts to exchange traded mutual funds. Each individual mutual fund or common collective trust has been selected based on its investment strategy, which approximates a specific asset class within our target allocation.

	Target	Actual Allocation	
(%)	Allocation	2013	2012
Asset Class (a)			
Cash	—	3	—
Equity Securities			
U.S. Equity Securities	32	53	48
Foreign Equity Securities	19	11	13
Domestic Real Estate	7	6	13
Inflation Indexed Securities	13	—	—
	71	70	74
Fixed Income Securities	29	27	26
	100	100	100

(a) Each mutual fund and common collective trust has been categorized based on its primary investment strategy.

The mutual funds are categorized as Level 1 in the fair value hierarchy as the fair value of the mutual funds is determined based on the quoted market price of each fund. The common/collective trusts are categorized as Level 2 in the fair value hierarchy. The fair value of the common/collective trusts were determined based on the net asset value as published by the respective fund manager multiplied by the number of units held in the trust. For our investments in the common/collective trusts, there were no restrictions on our ability to sell these investments. The respective level within the fair value hierarchy is determined as described in Note 1 of the Notes to Consolidated Financial Statements. The following represents the fair value of plan assets:

($000)	2013	Level 1	Level 2	Level 3
Asset Class (a)				
Cash	778	778	—	—
Exchange Traded Mutual Funds				
U.S. Equity Securities	14,191	14,191	—	—
Fixed Income Securities	6,969	6,969	—	—
Foreign Equity Securities	2,756	2,756	—	—
Domestic Real Estate Securities	1,507	1,507	—	—
	25,423	25,423	—	—
Total	26,201	26,201	—	—

($000)	2012	Level 1	Level 2	Level 3
Asset Class (a)				
Cash	31	31	—	—
Exchange Traded Mutual Funds				
U.S. Equity Securities	696	696	—	—
Fixed Income Securities	1,115	1,115	—	—
Foreign Equity Securities	1,062	1,062	—	—
Domestic Real Estate Securities	2,737	2,737	—	—
	5,610	5,610	—	—
Common Collective Trusts				
Short-Term Income Fund	148	—	148	—
U.S. Fixed Income Fund	2,202	—	2,202	—
Global Equity Growth Fund	2,472	—	2,472	—
Global Equity Value Fund	1,136	—	1,136	—
U.S. Equity Index Fund	2,098	—	2,098	—
Foreign Equity Index Fund	1,694	—	1,694	—
Blended Fund (b)	5,580	—	5,580	—
	15,330	—	15,330	—
Total	20,971	5,641	15,330	—

(a) Each mutual fund and common collective trust has been categorized based on its primary investment strategy.
(b) The blended fund is a combination of the U.S. equity securities (65%) and U.S. fixed income securities (35%).

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 $2,800,000 of discretionary contributions to the defined benefit plan in fiscal 2013. We expect to contribute $500,000 to the defined benefit plan in fiscal 2014.

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

($000)

2014	931
2015	2,599
2016	898
2017	1,029
2018	1,551
2019 - 2023	7,051

Effective May 9, 2008, any employees hired on and after that date were not eligible to participate in our defined benefit plan. Freezing the defined benefit 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 pension plan for retired employees.

(b) Employee Savings Plan We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 4% of the employee's annual compensation. 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 Savings Plan account. Company contributions are discretionary and subject to change with approval from our Board of Directors. For 2013, 2012 and 2011, Delta's Savings Plan expense was $313,000, $325,000 and $301,000, respectively.

(c) Supplemental Retirement Agreement We sponsor a nonqualified defined contribution supplemental retirement agreement for Glenn R. Jennings, Delta's Chairman of the Board, President and Chief Executive Officer. Delta contributes $60,000 annually into an irrevocable trust until Mr. Jennings' retirement. At retirement, the trustee will make annual payments of $100,000 to Mr. Jennings until the trust is depleted. As of June 30, 2013 and 2012, the irrevocable trust assets are $739,000 and $590,000, 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 28,436, 38,929 and 44,632 shares in 2013, 2012 and 2011, respectively. We registered 400,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2013 there were 122,000 shares available for issuance.

(8) Risk Management and Derivative Instruments

To varying degrees, our regulated and non-regulated segments are exposed to commodity price risk. We purchase our gas supply through a combination of spot market natural gas purchases and forward natural gas purchases. We mitigate price risk by efforts to balance supply and demand. 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, 2013 and June 30, 2012. We did not borrow from the bank line of credit during 2013. The maximum amount borrowed during 2012 was $6,491,000. The bank line of credit extends through June 30, 2015. The interest rate on the used line of credit is the London Interbank Offered Rate plus 1.15%. The annual cost of the unused bank line of credit is .125%. We were in compliance with the covenants of our bank line of credit (as further discussed in Note 10 of the Notes to Consolidated Financial Statements) during all periods presented in the Consolidated Financial Statements.

(10) Long-Term Debt

In December, 2011, we refinanced and redeemed our 5.75% Insured Quarterly Notes ($38,450,000) and 7% Debentures ($19,410,000) from the proceeds of a private debt financing. Under the Note Purchase and Private Shelf Agreement we issued $58,000,000 of Series A Notes, for which the purchasers paid 100% of the face principal amount. Unamortized debt expense of $1,896,000 related to the 5.75% Insured Quarterly Notes and 7% Debentures was reclassified from unamortized debt expense to regulatory assets on the accompanying Consolidated Balance Sheet. The $1,896,000 regulatory asset representing the loss on extinguishment of the 5.75% Insured Quarterly Notes and 7% Debentures, combined with $1,872,000 of unamortized loss on extinguishment of debt recognized from prior refinancings, will be amortized over the life of the 4.26% Series A Notes consistent with treatment approved by the Kentucky Public Service Commission.

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)	
2014	1,500
2015	1,500
2016	1,500
2017	1,500
Thereafter	50,500
Total long-term debt	56,500

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. At June 30, 2013 and 2012, the unamortized balance was $3,486,000 and $3,740,000, respectively. Loss on extinguishment of debt of $3,389,000 and $3,636,000 included in the above has been deferred as a regulatory asset and is being amortized over the term of the related debt consistent with regulatory accounting 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 covenants. Noncompliance with these covenants can make the obligation 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.

As of June 30, 2013, we were in compliance with all financial covenants.

The following table shows the required and actual financial covenants under our Series A Notes as of June 30, 2013:

	Requirement	**Actual**
Tangible net worth	no less than $25,800,000	$ 68,674,245
Debt to capitalization ratio	no more than 70%	45%
Fixed charge coverage ratio	no less than 1.20x	7.75 x
Dividends paid	no more than $28,318,000	$ 8,526,000

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.

(11) Earnings per Share

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

	2013	2012	2011
Numerator - Basic and Diluted			
Net income ($000)	7,201	5,784	6,365
Dividends paid ($000)	(4,951)	(4,762)	(4,562)
Undistributed earnings ($000)	2,250	1,022	1,803
Percentage allocated to common shares (a)	99.4%	99.6%	99.9%
Undistributed earnings allocated to common shares ($000)	2,238	1,018	1,801
Dividends paid on common shares outstanding ($000)	4,930	4,747	4,557
Net income available to common shares ($000)	7,168	5,765	6,358
Denominator			
Basic - weighted average common shares	6,843,455	6,777,186	6,707,224
Incremental unvested non-participating shares (b)	—	—	5,580
Diluted - weighted-average common shares	6,843,455	6,777,186	6,712,804
Per common share net income ($)			
Basic	1.05	0.85	0.95
Diluted	1.05	0.85	0.95
(a) Percentage allocated to common shares - weighted average			
Common shares outstanding	6,843,455	6,777,186	6,707,224
Unvested participating shares (c)	38,417	28,082	8,000
Total	6,881,872	6,805,268	6,715,224
Percentage allocated to common shares	99.4%	99.6%	99.9%

(b) Under our Incentive Compensation Plan, recipients of performance share awards receive unvested non-participating shares, as further discussed in Note 17 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 in (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 antidilutive shares in 2013, 2012 and 2011.

(c) Certain awards under our shareholder approved incentive compensation plan, as further discussed in Note 17 of the Notes to Consolidated Financial Statements, provide the recipients of the awards all the rights of a shareholder of Delta including a 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. There were no antidilutive shares in 2013, 2012 and 2011. There were 68,000 and 48,000 unvested participating shares outstanding as of June 30, 2013 and 2012, 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 $71,000, $70,000 and $72,000 for the years ended June 30, 2013, 2012 and 2011, 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 or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $4.2 million would be paid in addition to continuation of specified benefits for up to five years. Additionally, upon a change in control, all unvested shares awarded under our Incentive Compensation Plan, as further discussed in Note 17 of the Notes to Consolidated Financial Statements, would immediately vest.

Our June 30, 2012 Consolidated Balance Sheet includes $3,055,000 of accrued taxes and $877,000 of interest related to an assessment of a license tax levied on the gross receipts of Delta Resources' customers over the period of July, 2005 through September, 2011. The assessment was resolved in February, 2013 and the previously accrued interest was reversed. Delta Resources billed its customers $2,546,000 which represents their proportionate share of the assessment, as Delta Resources has a contractual right to seek reimbursement from its customers. As of June 30, 2013, the net receivable from Delta Resources' customers was $1,016,000. We will continue to pursue collection of the taxes from these customers and to monitor the amount of the receivable to be realized.

On the Consolidated Balance Sheets, the receivable from Delta Resources' customers is included in accounts receivable. On the June 30, 2012 Consolidated Balance Sheet, the liability for taxes was included in accrued taxes, and the liability for interest was included in accrued interest on debt. In the Consolidated Statements of Income, the change in the interest accrued is included in other interest (income) expense.

We are not a party to any material pending legal proceedings.

We have entered into forward purchase agreements beginning in July, 2013 and expiring at various dates through December, 2013. These agreements require us to purchase minimum amounts of natural gas throughout the term of the agreements. These agreements are established in the normal course of business to ensure adequate gas supply to meet our customers' gas requirements. These agreements have aggregate remaining minimum purchase obligations of $328,000 for our fiscal year ending June 30, 2014.

(14) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. Their regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas and transportation services. They have historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of gas costs, and a reasonable rate of return. Our regulated rates were most recently adjusted in our 2010 rate case and became effective in October, 2010. In this case, the Kentucky Public Service Commission approved increased base rates to provide an additional $3,513,000 in annual revenues based upon a 10.4% allowed return on common equity and a $1,770,000 increase in annual depreciation expense. A majority of the increase was allocated to our fixed monthly customer charge as opposed to the volumetric rate, and therefore the increase in revenues is less dependent on customer usage and occurs more evenly throughout the year. We do not have any matters before the Kentucky Public Service Commission that would have a material impact on our results of operations, financial position or cash flows.

We have a pipe replacement program which 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.

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

Additionally, we have a weather normalization provision in our tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

The Kentucky Public Service Commission allows us a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customer's interests by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

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

(15) Segment Information

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

In our non-regulated segment, two customers each provided more than 5% of our operating revenues. Our largest customer provided approximately $17,866,000, $12,450,000 and $11,461,000 of non-regulated revenues during 2013, 2012 and 2011, respectively. Our second largest customer provided approximately $5,390,000, $6,815,000 and $8,067,000 of non-regulated revenues during 2013, 2012 and 2011, respectively. There is no assurance that revenues from these customers will continue at these levels.

In 2013, we purchased approximately 98% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services. In 2012 and 2011, we purchased approximately 99% of our natural gas from Atmos Energy Marketing and M & B Gas Services.

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)	2013	2012	2011
Operating Revenues			
Regulated			
External customers	46,427	42,655	48,697
Intersegment	4,145	3,704	3,777
Total regulated	50,572	46,359	52,474
Non-regulated			
External customers	34,238	31,423	34,343
Eliminations for intersegment	(4,145)	(3,704)	(3,777)
Total operating revenues	80,665	74,078	83,040
Operating Expenses			
Regulated			
Purchased gas	17,825	15,703	21,078
Depreciation and amortization	6,023	5,871	5,037
Other	14,701	13,909	14,318
Total regulated	38,549	35,483	40,433
Non-regulated			
Purchased gas	26,011	23,380	26,762
Depreciation and amortization	70	53	120
Other	6,990	5,601	5,440
Total non-regulated	33,071	29,034	32,322
Eliminations for intersegment	(4,145)	(3,704)	(3,777)
Total operating expenses	67,476	60,813	68,978
Other Income and Deductions, Net			
Regulated	151	77	153
Non-regulated	—	(2)	(1)
Total other income and deductions	151	75	152
Interest Charges			
Regulated	2,688	3,366	4,029
Non-regulated	(818)	932	60
Total interest charges	1,870	4,298	4,089
Income Tax Expense			
Regulated	3,676	2,772	3,012
Non-regulated	593	486	748
Total income tax expense	4,269	3,258	3,760
Net Income			
Regulated	5,970	4,990	5,153
Non-regulated	1,231	794	1,212
Total net income	7,201	5,784	6,365
Assets			
Regulated	177,662	174,454	168,997
Non-regulated	6,268	8,441	5,899
Total assets	183,930	182,895	174,896
Capital Expenditures			
Regulated	6,983	7,163	8,120
Non-regulated	196	174	3
Total capital expenditures	7,179	7,337	8,123

(16) Insurance Proceeds

In September, 2011, we received $300,000 of insurance proceeds relating to a gas inventory adjustment recorded in fiscal 2009 for the Company's underground storage field. These proceeds are included in operation and maintenance in the 2012 Consolidated Statement of Income.

(17) 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 which may be issued pursuant to the Plan may not exceed in the aggregate 1,000,000 shares. As of June 30, 2013, 850,000 shares of common stock were available for issuance under the Plan. Shares of common stock may be issued from authorized but unissued shares, shares reacquired by us or shares that we purchase in the open market.

Compensation expense for share-based compensation is recorded in the non-regulated segment and included 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. Our share-based compensation expense was $922,000, $712,000 and $527,000 for 2013, 2012 and 2011, respectively.

Tax benefits of $26,000 and $22,000 were recognized as a premium on common shares on our 2013 and 2012 Consolidated Balance Sheets, respectively, which decreased our taxes payable as the deduction for income tax purposes exceeds the compensation expense recognized for share-based compensation. The excess tax benefits can be utilized to offset tax deficiencies related to share-based compensation in subsequent periods.

Stock Awards

In 2013 and 2012, common stock was awarded to virtually all Delta employees and directors having grant date fair values of $264,000 (12,000 shares) and $337,000 (22,000 shares), respectively. 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 2013 and 2012, performance shares were awarded to the Company's executive officers having grant date fair values of $844,000 (39,000 shares) and $552,000 (36,000 shares), respectively. The performance share awards 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 equally over a three-year period beginning each August 31 subsequent to achieving the performance objectives as long as the recipients are employees throughout each such service period. 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.

As of June 30, 2013 the performance objectives for the performance shares awarded in 2013 have been satisfied and subject to further limitations of the plan, up to 39,000 unvested shares will be issued to the recipients, subject to a service condition whereby a recipient of the award shall vest in one-third increments each year beginning August 31, 2013 and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. The performance objectives for the performance shares awarded in 2012 were met and 27,000 unvested shares were issued on August 31, 2012, of which 18,000 shares remain unvested as of June 30, 2013.

For 2013 and 2012, compensation expense related to the performance shares was $658,000 and $375,000, respectively. Compensation expense of $431,000 is expected to be recognized between 2014 and 2016 for the unvested shares.

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, 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, 2013 is 1.6 years.

The following summarizes the activity for performance shares:

	Performance shares	
	Number of shares	Weighted-average grant date fair value
Unvested shares at June 30, 2011	32,000	$ 14.67
Granted (1)	36,000	$ 15.32
Vested	(10,666)	(14.67)
Forfeited (2)	(9,000)	(15.32)
Unvested shares at June 30, 2012	48,334	$ 15.03
Granted (1)	39,000	$ 21.63
Vested	(19,666)	(14.96)
Unvested shares at June 30, 2013	67,668	$ 18.85

(1) Represents the maximum number of shares which could be issued based on achieving the performance criteria.
(2) Represents the number of shares awarded but not earned based on the actual performance criteria achieved.

(18) Quarterly Financial Data (Unaudited)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Basic Earnings (Loss) per Common Share	Diluted Earnings (Loss) per Common Share
Fiscal 2013					
September 30	$ 11,452,315	$ 415,946	$ (158,903)	$ (0.02)	$ (0.02)
December 31	22,106,691	4,967,855	3,249,376	0.47	0.47
March 31	31,133,349	7,323,064	4,242,677	0.62	0.62
June 30	15,972,482	481,814	(132,374)	(0.02)	(0.02)
Fiscal 2012					
September 30	$ 12,896,327	$ 566,101	$ (797,126)	$ (0.12)	$ (0.12)
December 31	22,526,345	4,984,294	2,512,238	0.37	0.37
March 31	26,716,070	6,971,971	3,925,295	0.58	0.58
June 30	11,939,580	742,862	143,591	0.02	0.02

(19) Subsequent Events

In August, 2013, 17,000 shares of common stock was awarded to virtually all Delta employees and directors having a grant date fair value of $350,000. Additionally, in August, 2013, performance shares were awarded to the Company's executive officers. The performance share awards vest only if the performance objective of the awards is met, which is based on the Company's fiscal 2014 audited earnings per share, before any cash bonuses or share-based compensation. Subject to further limitations described in the Plan, all performance shares paid shall be in the form of unvested shares, which contain a service condition whereby recipients of the awards shall vest in one-third increments each year beginning on August 31, 2014, and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. The maximum number of shares which could be issued under the performance awards is 39,000, having a grant date fair value of $801,000.

DELTA NATURAL GAS COMPANY, INC.

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED JUNE 30, 2013, 2012 and 2011

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, 2013	$ 157,000	$ 496,512	$ 140,178	$ 257,435	$ 536,255
June 30, 2012	190,000	127,891	168,204	329,095	157,000
June 30, 2011	273,000	67,359	170,810	321,169	190,000

Exhibit 13-2

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, 2014

☐ **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 ☐

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. $155,037,002.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. As of August 15, 2014, Delta Natural Gas Company, Inc. had outstanding 6,943,547 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, 2014, 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, "2014", "2013" and "2012" refers to the respective twelve month periods ending June 30.

General

Delta Natural Gas Company, Inc. ("Delta" or "the Company") (Nasdaq: DGAS) 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 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 sell liquids extracted from natural gas in our storage field and on our pipeline systems. We have three wholly-owned subsidiaries. Delta Resources, Inc. ("Delta Resources") buys natural gas and resells it to industrial or large use 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 minimizing our exposure to market risk arising from fluctuations in the prices of natural gas.

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.

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 industrial 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. Financial Statements and Supplementary Data and under "Regulatory Matters" in Item 1. Business.

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 a fixed monthly customer charge and a volumetric rate which has a weather normalization provision 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 2014, 76% 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. The Kentucky Public Service Commission, through a weather normalization provision in our tariff, permits us to adjust the rates we charge our customers in response to winter weather that is warmer or colder than normal temperatures.

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

Our larger 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 and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most 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 delivery systems other than ours, which generates competition for our transportation services. We continue our efforts to purchase or transport natural gas that is produced in reasonable proximity to our transportation facilities through our regulated segment.

As an active participant in many areas of the natural gas industry, we plan to continue efforts to expand our 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.

Gas Supply

We maintain an active 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. In our fiscal year ended June 30, 2014, 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 gas marketers. We currently have commodity requirements agreements with Atmos Energy Marketing (“Atmos”) for our Columbia Gas Transmission Corporation (“Columbia Gas”), Columbia Gulf Transmission Corporation (“Columbia Gulf”), Tennessee Gas Pipeline (“Tennessee”) and Texas Eastern Transmission Corporation (“Texas Eastern”) supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. We are not obligated to purchase any minimum quantities from Atmos or 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 for the indices that relate to the pipelines through which the natural gas will be transported, 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 Atmos 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, 2014, approximately 37% of our regulated natural gas supply was purchased under our agreements with Atmos.

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, 2014, approximately 61% 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 either current market prices, determined by industry publications, or at forward market prices.

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. We intend 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 2014, Tennessee transported for us a total of 1,100,000 Mcf, or approximately 23% 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 Atmos, 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 2014, Columbia Gas and Columbia Gulf transported for us a total of 675,000 Mcf, or approximately 14% of our regulated natural gas supply requirements, under all of our agreements with them. Our transportation agreements with Columbia Gas and Columbia Gulf extend through 2015. After 2015, our agreement with Columbia Gas continues on a year-to-year basis unless terminated by one of the parties, but 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 2014 constituted approximately 61% of our regulated gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the natural gas to us that we purchase from Atmos to supply our customers' requirements in specific geographic areas. In our fiscal year ended June 30, 2014, Texas Eastern transported approximately 18,000 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 45,000 Mcf from Vinland during fiscal 2014. The price for the natural gas we purchase from Vinland is based on the index price of spot 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 2014, the natural gas we purchased from Vinland constituted less than 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. Their regulation of our business includes approving the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas and transportation services. They have historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of gas costs, and a reasonable rate of return. 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 positions or cash flows.

We have a pipe replacement program which 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 is designed to additionally recover the costs associated with the mandatory retirement or relocation of facilities.

The Kentucky Public Service Commission allows us a natural gas cost recovery clause, which 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 clause, 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.

Additionally, we have a weather normalization provision in our tariffs, approved by the Kentucky Public Service Commission, which 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.

The Kentucky Public Service Commission also allows us a conservation and efficiency program for our residential customers. 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 margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in four other cities we serve. In the other cities and areas we serve, 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.

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 larger non-regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the 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, 2014, approximately 94% of our non-regulated revenue was derived from our natural gas marketing activities. In our non-regulated segment, three customers each provided more than 5% of our operating revenues for 2014 and two customers each provided more than 5% for 2013 and 2012. Seminole Energy provided approximately $9,494,000, $17,866,000 and $12,450,000 of non-regulated revenues during 2014, 2013 and 2012, respectively. Atmos provided approximately $5,206,000, $5,390,000 and $6,815,000 of non-regulated revenues during 2014, 2013 and 2012, respectively. Greystone, LLC provided approximately $12,569,000 of non-regulated revenues during 2014. 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. Item 2. Properties further describes Enpro's oil and natural gas leases and production properties. Enpro produced a total of 80,000 Mcf of natural gas during 2014 which was approximately 1% of our non-regulated volumes sold.

Natural Gas Liquids

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 sell these natural gas liquids at a price determined by a national unregulated market. In our fiscal year ended June 30, 2014, approximately 5% 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 M & B Gas Services (“M&B”) and Midwest. Our underlying agreements with M&B and Midwest do not obligate us to purchase any minimum quantities from M&B or Midwest, nor to purchase natural gas from either company 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 agreements with both M&B and Midwest may be terminated upon 30 days prior written notice by either party. Any purchase agreements to supply our unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2014, 1% and 90% of our non-regulated natural gas supply was purchased under our agreements with M&B and Midwest, respectively.

Additionally, our non-regulated segment purchases natural gas from Atmos as needed. This spot gas purchasing arrangement is pursuant to an agreement with Atmos containing an “evergreen” clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from Atmos under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing 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, 2014, approximately 9% of our non-regulated natural gas supply was purchased under our agreement with Atmos.

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.

Capital Expenditures

Capital expenditures during 2014 were $8.1 million and for 2015 are estimated to be $10.8 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are met through the use of internally generated funds and a short-term bank line of credit. The current available line of credit is $40 million, all of which was available at June 30, 2014.

Our current bank line of credit extends through June 30, 2015 and will be utilized to meet capital expenditure and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

We currently have long-term debt of $55,000,000 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, 2014, we had 150 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, annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the 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,	2014	2013	2012	2011	2010
Average Regulated Customers Served					
Residential	29,588	29,755	29,929	30,420	30,575
Commercial	4,861	4,906	4,890	4,949	4,957
Industrial	41	40	41	44	46
Total	34,490	34,701	34,860	35,413	35,578
Operating Revenues ($000) (a)					
Regulated (b)					
Residential sales	29,867	24,342	22,720	25,800	23,783
Commercial sales	20,294	15,849	14,026	16,672	15,894
Industrial sales	1,381	1,011	914	1,199	1,075
On-system transportation	5,416	5,237	4,780	4,830	4,421
Off-system transportation	3,747	3,800	3,595	3,670	3,650
Other	390	333	324	303	294
Total regulated revenues	61,095	50,572	46,359	52,474	49,117
Non-regulated sales	38,792	34,238	31,423	34,343	30,746
Intersegment eliminations (c)	(4,041)	(4,145)	(3,704)	(3,777)	(3,441)
Total	95,846	80,665	74,078	83,040	76,422
System Throughput (Million Cu. Ft.) (a)					
Regulated					
Residential sales	1,814	1,659	1,331	1,737	1,756
Commercial sales	1,420	1,291	1,027	1,310	1,331
Industrial sales	117	107	90	120	111
On-system transportation	4,807	4,988	4,724	4,830	4,533
Off-system transportation	11,616	11,795	11,225	11,531	11,039
Total regulated throughput	19,774	19,840	18,397	19,528	18,770
Non-regulated sales	7,241	7,650	6,455	6,010	4,787
Intersegment eliminations (c)	(7,096)	(7,497)	(6,326)	(5,890)	(4,692)
Total	19,919	19,993	18,526	19,648	18,865
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	61	56	44	57	57
Lexington, Kentucky Degree Days					
Actual	4,855	4,667	3,797	4,725	4,782
Percent of 30 year average	107	104	83	103	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) We implemented new regulated base rates, as approved by the Kentucky Public Service Commission in October, 2010, which were designed to generate additional annual revenue of $3,513,000.

(c) Intersegment eliminations represent the natural gas transportation costs from the regulated segment to the non-regulated segment at our tariff rates.

Item 1A. Risk Factors

The risk factors below should be carefully considered.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR.

Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 76% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in the amount of natural gas we sell in any year, which would reduce our revenues and profits. The weather normalization provision in our 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.

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 larger 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 by-passes in order to achieve lower prices for their natural gas and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution and transportation systems creates a risk of the loss of large customers and thus could result in lower revenues and profits.

ACTIONS BY OUR REGULATORS COULD DECREASE FUTURE PROFITABILITY.

We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our operating revenues. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases, may decrease our rates or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our increased costs of natural gas. Such regulatory actions would decrease our revenues and our profitability. Additionally, our consolidated financial statements reflect the application of regulatory accounting standards by our regulated segment. 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 income and consolidated financial statements.

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 unregulated market, and decreases in the price could result in a decrease in our non-regulated gross margins.

DERIVATIVES LEGISLATION COULD ADVERSELY AFFECT OUR ABILITY TO HEDGE RISKS ASSOCIATED WITH OUR BUSINESS OR OTHERWISE HAVE A MATERIAL AND ADVERSE EFFECT ON OUR FINANCIAL POSITION, RESULTS OF OPERATIONS OR CASH FLOWS.

We currently use, and historically have used, forward commodity contracts, which meet the criteria of a derivative. The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") adopted a comprehensive framework for the regulation of over-the-counter swaps ("OTC swaps"). The Dodd-Frank Act divides regulatory authority over swap agreements between the SEC and the Commodity Futures Trading Commission ("CFTC") and requires that most OTC swaps be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. While the SEC and CFTC have adopted numerous regulations relating to OTC swaps, they are still in the process of rulemaking to address all of the requirements regarding OTC swaps under the Dodd-Frank Act. Current and future legal and regulatory requirements, restrictions and regulations imposed under the Dodd-Frank Act could increase the operational and transactional cost of derivatives contracts and could affect the number and/or creditworthiness of available counterparties, which could affect our ability to hedge our business risk.

INTERSTATE AND OTHER PIPELINES DELTA INTERCONNECTS WITH CAN IMPOSE RESTRICTIONS ON THEIR PIPELINE.

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

FUTURE PROFITABILITY OF THE NON-REGULATED SEGMENT IS DEPENDENT ON A FEW INDUSTRIAL AND OTHER LARGE-VOLUME CUSTOMERS.

Our larger non-regulated customers are primarily industrial and other large-volume customers. Fluctuations in 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 NATURAL GAS SUPPLY, 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 unregulated market. A reduction in the quantity of liquids present in our natural gas supply, 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 PENSION PLAN HOLDINGS AND OTHER FACTORS IMPACTING PENSION PLAN COSTS COULD UNFAVORABLY IMPACT OUR LIQUIDITY AND RESULTS OF OPERATIONS.

Our cost of providing a non-contributory defined benefit pension plan is dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding 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. Such cash funding obligations 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 cash flows, financial position or results of operations.

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, the breakdown or failure of equipment or processes, the performance of pipeline and storage facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond our control. These risks could result in injury or loss of life, extensive property damage 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 OR WELL-HEAD DISASTERS COULD DISRUPT OUR NATURAL GAS SUPPLY AND INCREASE NATURAL GAS PRICES.

Hurricanes, extreme weather or well-head 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. Such events could also result in new governmental regulations or rules that limit production or raise production costs.

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 business, results of operations and financial condition.

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, 2014 our Series A Notes permit us to pay up to $22,778,000 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 that 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 enough individuals who are knowledgeable about the natural gas industry and/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, cash flows, results of operations 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 results of operations, financial condition and cash flows.

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 2,500 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. Business.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business. Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.5 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others for further drilling and development. We have performed no reserve studies on these properties. Enpro produced a total of 80,000 Mcf of natural gas during fiscal 2014 from all the properties described in this paragraph.

A producer plans to conduct further exploration activities on part of Enpro's developed holdings. Enpro reserves the option to participate in wells drilled by this producer and also retains certain working and royalty interests in any production from future wells.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

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

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.

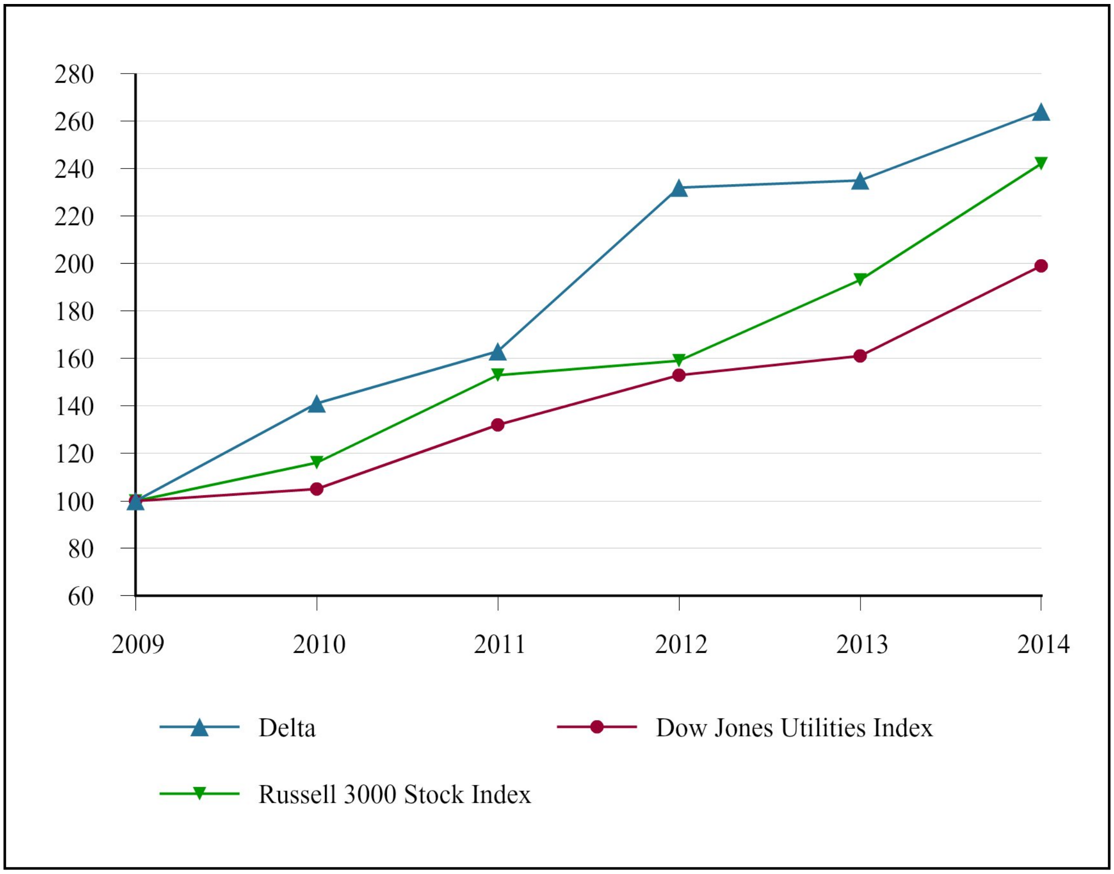
Our common stock is listed on NASDAQ and trades under the symbol “DGAS”. There were 1,482 record holders of our common stock as of August 26, 2014. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ stock market and the cash dividends declared per share.

Quarter	Range of Stock Prices ($) High	Low	Dividends Per Share ($)
Fiscal 2014			
First	25.02	18.50	.19
Second	22.90	19.98	.19
Third	22.29	18.44	.19
Fourth	22.13	18.43	.19
Fiscal 2013			
First	24.82	18.41	.18
Second	22.16	17.08	.18
Third	22.08	18.88	.18
Fourth	24.18	19.99	.18

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.

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, 2009 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.



	2009	2010	2011	2012	2013	2014
Delta	100	141	163	232	235	264
Dow Jones Utilities Index	100	105	132	153	161	199
Russell 3000 Stock Index	100	116	153	159	193	242

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,	2014	2013	2012	2011	2010
Summary of Operations ($)					
Operating revenues (a)	95,845,871	80,664,837	74,078,322	83,040,251	76,422,068
Operating income (a)	15,603,439	13,188,679	13,265,228	14,061,794	12,904,494
Net income (a)(b)	8,275,128	7,200,776	5,783,998	6,364,895	5,651,817
Earnings per common share (a)(b)					
Basic and diluted	1.19	1.05	.85	.95	.85
Cash dividends declared per common share	.76	.72	.70	.68	.65
Weighted Average Number of Common Shares					
Basic	6,918,725	6,843,455	6,777,186	6,707,224	6,652,320
Diluted	6,918,725	6,843,455	6,777,186	6,712,804	6,652,320
Total Assets ($)	186,025,161	183,930,015	182,895,363	174,896,239	168,632,420
Capitalization ($)					
Common shareholders' equity	74,728,352	70,005,415	66,220,407	63,767,184	60,760,170
Long-term debt	53,500,000	55,000,000	56,500,000	56,751,006	57,112,000
Total capitalization	128,228,352	125,005,415	122,720,407	120,518,190	117,872,170
Short-Term Debt ($) (c)	1,500,000	1,500,000	1,500,000	1,200,000	1,200,000
Other Items ($)					
Capital expenditures	8,077,642	7,179,473	7,337,115	8,123,479	5,275,194
Total property, plant and equipment	229,367,319	223,545,925	217,172,542	211,409,336	204,248,520

(a) We implemented new regulated base rates as approved by the Kentucky Public Service Commission in October, 2010 and the rates were designed to generate additional annual revenue of $3,513,000, with a $1,770,000 increase in annual depreciation expense.
(b) In 2012, $877,000 of interest expense was accrued relating to a tax assessment. In 2013, the assessment was resolved and the previously accrued interest was reversed.
(c) Includes current portion of long-term debt.

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

Overview of 2014 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 2014. Our Company has two segments: (i) a regulated natural gas distribution and transmission segment, and (ii) a non-regulated segment which participates in related activities, consisting of natural gas marketing, natural gas production and the sale of liquids extracted from natural gas.

Earnings from the regulated segment are primarily influenced by sales and transportation volumes, the rates we charge our customers and the expenses we incur. In order for us to achieve our strategy of maintaining reasonable long-term earnings, cash flow and stock value, we must successfully manage each of these factors. Regulated sales volumes are temperature-sensitive. Our regulated sales volumes in any period reflect the impact of weather, with colder temperatures generally resulting in increased sales volumes. The impact of winter temperatures on our revenues is partially reduced 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 also produces natural gas and sells liquids extracted from natural gas.

Consolidated earnings per common share for 2014 increased $0.14 per common share as compared to 2013. We experienced a winter that was colder than the preceding year resulting in increased volumes of natural gas sold. Additionally, sales of natural gas liquids increased, as compared to the prior year. Other factors which influenced our 2014 consolidated earnings per common share are further discussed in the Results of Operations.

Future Outlook

Future profitability of the regulated segment is contingent on the adequate and timely adjustment of the rates we charge our regulated customers. The Kentucky Public Service Commission sets these rates, and we monitor our need to file rate cases with the Kentucky Public Service Commission for a general rate increase for our regulated services. 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 2015. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated segment gross margins related to our natural gas production and marketing activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated gross margins related to our natural gas production and marketing activities. The profitability of selling natural gas liquids is dependent on the amount of liquids extracted and the pricing for any such liquids, which is determined by a national unregulated market.

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, 2015 and permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit as of June 30, 2014 or June 30, 2013.

Cash and cash equivalents were $13,676,000 at June 30, 2014 compared with $10,360,000 at June 30, 2013 and $9,741,000 at June 30, 2012. These changes in cash and cash equivalents are summarized in the following table:

$(000)	2014	2013	2012
Provided by operating activities	17,340	13,557	13,514
Used in investing activities	(7,870)	(7,108)	(7,012)
Used in financing activities	(6,155)	(5,829)	(4,102)
Increase in cash and cash equivalents	3,315	620	2,400

In 2014, cash provided by operating activities increased $3,783,000 (28%), as compared to 2013, due to increased cash received from customers as a result of increased sales, partially offset by increased amounts paid for natural gas.

In 2013, there was not a significant change in cash provided by operating activities as compared to 2012.

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

In 2014, there was not a significant change in cash used in financing activities, as compared to 2013.

In 2013, cash used in financing activities increased $1,727,000 (42%) , as compared to 2012, due to the first annual $1,500,000 repayment on our 4.26% Series A Notes.

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, storage and general facilities. We expect our capital expenditures for fiscal 2015 to be approximately $10.8 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2014:

	Payments Due by Fiscal Year				
$(000)	2015	2016 - 2017	2018 - 2019	After 2019	Total
Interest payments (a)	2,360	4,427	4,171	20,249	31,207
Long-term debt (b)	1,500	3,000	3,000	47,500	55,000
Pension contributions (c)	500	1,000	1,000	4,500	7,000
Natural gas purchases (d)	140	—	—	—	140
Total contractual obligations (e)	4,500	8,427	8,171	72,249	93,347

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2014 interest payments until the underlying obligation is satisfied. As of June 30, 2014, we have also accrued $5,000 of interest related to uncertain tax positions. These amounts have been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(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 plan through 2028, as recommended by our actuary.

(d) As of June 30, 2014, we had a contract which had a minimum purchase obligation. The contract term expires December, 2014. 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 ($40,538,000), regulatory liabilities ($1,165,000), asset retirement obligations ($3,261,000) and deferred compensation ($907,000). 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 sets 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 will be sufficient to satisfy our operating and normal capital expenditure requirements and to pay dividends for the next twelve months and the foreseeable future. To the extent that internally generated cash is not sufficient to satisfy seasonal operating and capital expenditure requirements and to pay dividends, we rely on our bank line of credit.

In December, 2011, we refinanced our 5.75% Insured Quarterly Notes and 7% Debentures from the proceeds of a private debt financing. Under the Note Purchase and Private Shelf Agreement, we issued $58,000,000 of Series A Notes, for which the purchasers paid 100% of the face principal amount. The proceeds from the sale of the Series A Notes were used to fund the redemption of our 5.75% Insured Quarterly Notes Due April 1, 2021, which had an outstanding principal balance of $38,450,000, and our 7% Debentures Due February 1, 2023, which had an outstanding principal balance of $19,410,000.

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, 2014:

	Requirement	Actual
Tangible net worth	no less than $25,800,000	$73,961,000
Debt to capitalization ratio	no more than 70%	42%
Fixed charge coverage ratio	no less than 1.20x	8.79 x
Dividends paid	no more than $36,594,000	$13,816,000

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 rate-making 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 of regulatory accounting, that segment will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on our consolidated financial statements.

The application of 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.

Pension

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 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, 2014, 2013 and 2012, we recorded pension costs for our defined benefit pension plan of $750,000, $980,000 and $481,000, 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 in the future over the average remaining service period of active plan participants. As of June 30, 2014, $5,824,000 of net losses have been deferred for amortization as pension costs into future periods.

Our pension plan assets are principally comprised of equity and fixed income investments. Differences between actual portfolio returns and expected returns will 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 pension plan assets was 6% for 2014 and was based on our targeted asset allocation assumption for 2014 of approximately 70% equity investments and approximately 30% 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. 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 6%, discount rate of 4.25%, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plan will decrease from $750,000 in 2014 to $493,000 in 2015. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2015 by approximately $71,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $100,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $106,000.

Unbilled Revenues and Gas Costs

At each month-end, we estimate the natural gas service that has been rendered from the date the customer's meter was last read to month-end. This estimate of unbilled usage is based on projected base load usage for each day unbilled plus projected weather-sensitive usage for each degree day during the unbilled period. Unbilled revenues and 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.

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations is recorded at the time the obligations are incurred. We do not recognize asset retirement obligations relating to assets with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities accrete for the change in their present value, and the initial capitalized costs depreciate over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the accretion and depreciation are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement dates and the assumed credit-adjusted risk-free interest rates. Our asset retirement obligations are further discussed in Note 4 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as “estimates”, “attempts”, “expects”, “monitors”, “plans”, “anticipates”, “intends”, “continues”, “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,
- pension plan costs and management,
- contractual obligations and cash requirements,
- management of our natural gas supply and risks due to potential fluctuation in the price of natural gas,
- revenues, income, margins and profitability,
- efforts to purchase and transport locally produced natural gas,
- recovery of regulatory assets,
- 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. Risk Factors 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 of natural gas and natural gas liquids and the provision of natural gas transportation services. We define "gross margins" as natural gas sales less the corresponding purchased natural gas expenses, plus transportation, natural gas liquids and other revenues. 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. Gross margin can be derived directly from our Consolidated Statements of Income included in Item 8. Financial Statements and Supplemental Data, as follows:

($000)	2014	2013	2012
Operating revenues	95,846	80,665	74,078
Regulated purchased natural gas	(27,215)	(17,825)	(15,703)
Non-regulated purchased natural gas	(29,059)	(26,011)	(23,380)
Consolidated gross margins	39,572	36,829	34,995

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

In the following table we set forth variations in our gross margins for the last two 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)	2014 compared to 2013	2013 compared to 2012
Increase (decrease) in gross margins		
Regulated segment		
Natural gas sales	950	1,420
On-system transportation	179	457
Off-system transportation	(53)	205
Other	57	9
Intersegment elimination (a)	104	(441)
Total	1,237	1,650
Non-regulated segment		
Natural gas sales	1,053	(256)
Natural gas liquids	529	41
Other	28	(42)
Intersegment elimination (a)	(104)	441
Total	1,506	184
Increase in consolidated gross margins	2,743	1,834
Percentage increase (decrease) in volumes		
Regulated segment		
Natural gas sales (Mcf)	10	25
On-system transportation (Mcf)	(4)	6
Off-system transportation (Mcf)	(2)	5
Non-regulated segment		
Natural gas sales (Mcf)	(5)	19
Natural gas liquids (gallons)	39	34

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

Heating degree days were 107% of the normal thirty year average temperatures for fiscal 2014, as compared with 104% and 83% of normal temperatures for 2013 and 2012, respectively. A heating degree day is the equivalent for 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 degree days 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 2014, consolidated gross margins increased $2,743,000 (7%), as compared to 2013, due to increased non-regulated and regulated gross margins of $1,506,000 and $1,237,000, respectively. Non-regulated gross margins increased due to the increased sales of the non-regulated segment's natural gas production inventory and increased sales of natural gas liquids extracted from the natural gas in our system. Regulated gross margins increased due to a 10% increase in volumes sold to our regulated customers as a result of colder weather and increased amounts billed through our pipe replacement program tariff. Partially offsetting these increases are decreased rates billed through our weather normalization tariff.

In 2013, consolidated gross margins increased $1,834,000 (5%), as compared to 2012, due to increased regulated and non-regulated gross margins of $1,650,000 and $184,000, respectively. Regulated gross margins increased due to a 25% increase in volumes sold to our regulated customers as a result of colder weather and an increase in volumes transported as a result of an increase in our transportation customers' gas requirements. Partially offsetting these increases are decreased rates billed through our weather normalization tariff.

Operation and Maintenance

In 2014 there were no significant changes in operation and maintenance as compared to 2013.

In 2013, operation and maintenance increased $1,556,000 (11%) due to a $1,230,000 increase in labor and employee benefits resulting from an increase in pension expense and share-based compensation and a $369,000 increase in uncollectible expense.

Depreciation and Amortization

In 2014 and 2013, there were no significant changes in depreciation and amortization, as compared to 2013 and 2012, respectively.

Taxes Other Than Income Taxes

In 2014 and 2013, there were no significant changes in taxes other than income taxes, as compared to 2013 and 2012, respectively.

Interest on Long-Term Debt

In 2014, there were no significant changes in interest on long-term debt, as compared to 2013.

In 2013, interest on long-term debt decreased $546,000 (18%) as a result of refinancing our 5.75% Insured Quarterly Notes and 7% Debentures (as further discussed in Note 10 of the Notes to Consolidated Financial Statements).

Other Interest (Income) Expense

In 2014, other interest (income) expense increased $874,000 (106%), as compared to 2013 due to a decrease in interest accrued in the prior year relating to a resolution of a tax assessment (as further discussed in Note 13 of the Notes to Consolidated Financial Statements).

In 2013, other interest (income) expense decreased $1,807,000 (183%) due to a decrease in interest accrued for a tax assessment issued to Delta Resources by the Kentucky Department of Revenue (as further discussed in Note 13 of the Notes to Consolidated Financial Statements).

Income Tax Expense

In 2014, income tax expense increased $590,000 (14%) due to an increase in net income before taxes. There were no significant changes in our effective tax rate for 2014, as compared to 2013.

In 2013, income tax expense increased $1,011,000 (31%) due to an increase in net income before income taxes. There were no significant changes in our effective tax rate for 2013, as compared to 2012.

Basic and Diluted Earnings Per Common Share

For 2014 and 2013, our basic and diluted earnings per common share changed as a result of changes in net income and an increase in the number of our common shares outstanding. We increased our number of common shares outstanding as a result of shares issued through our Dividend Reinvestment and Stock Purchase Plan 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.

Under our Incentive Compensation Plan, recipients of performance share awards receive unvested non-participating shares, as further discussed in Note 17 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. 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, 2014 and 2013.

Certain unvested awards under our shareholder approved incentive compensation plan, as further discussed in Note 17 of the Notes to Consolidated Financial Statements, provide the recipients of the awards all the rights of a shareholder of Delta Natural Gas Company, Inc. 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 further discussed in Note 11 of the Notes to Consolidated Financial Statements. There were 74,000 and 68,000 unvested participating shares outstanding as of June 30, 2014 and 2013, respectively. There were no antidilutive shares as of June 30, 2014 and 2013.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We purchase our natural gas supply primarily through forward natural gas contracts. The price we pay for our natural gas supply acquired under these 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 have minimal price risk resulting from forward purchase and storage of natural gas because we are permitted to pass these natural gas costs on to our regulated customers through our natural gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission.

Price risk for the non-regulated business is mitigated by efforts to balance supply and demand. However, there are greater risks in the non-regulated segment because of the practical limitations on the ability to perfectly predict demand. In addition, we are exposed to 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 unregulated 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, 2014, we had a forward purchase contract totaling $140,000 that expires in December, 2014. The forward purchase contract is 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, 2014 or June 30, 2013. The weighted average interest rate on our bank line of credit was 1.3% as of June 30, 2014 and June 30, 2013, respectively. During 2014, we borrowed and repaid $691,000 from the bank line of credit, having a weighted average interest rate of 1.4%. A one percent (one hundred basis point) increase in our average interest rate would not have had a significant impact on our annual pre-tax net income. We did not have any borrowings on our bank line of credit during 2013.

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 Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2014 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, 2014 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, 2014 based on the framework in *Internal Control - Integrated Framework* issued in 1992 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, 2014.

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, 2014, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 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, 2014, based on the criteria established in *Internal Control - Integrated Framework (1992)* 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, 2014 of the Company and our report dated August 26, 2014 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 26, 2014

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 can be found on our website by going to the following address: http://www.deltagas.com/investor_relations.html. 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/corporate_governance.html.

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 2014 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2014. 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 2014 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2014. 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, 2014:

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)
—	—	793,760

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 2014 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2014. 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 2014 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2014. 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 2014 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2014. 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 15, 2014) are incorporated herein by reference to Exhibit 3.1 to Registrant's Form 8-K (File No. 000-8788) dated August 19, 2014.
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.
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.
10.04	Natural Gas Sales Agreement, dated May 1, 2010, by and between Atmos Energy Marketing, LLC and Registrant is 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.
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 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 November 1, 1993 (Service Agreement Nos. 37,813, 37,814 and 37,815), and Appendix A to respective Service Agreements, effective November 1, 2010, by and between Columbia Gas Transmission Corporation and Registrant incorporated herein by reference to Exhibit 10(g) to Registrant's Form 10-K (File No. 000-08788), for the period ended June 30, 2010.
10.10	FTS1 Service Agreements, dated October 4, 1994, (Service Agreement Nos. 43,827, 43,828 and 43,829), and Appendix A to respective Service Agreements, effective November 1, 2010, by and between Columbia Gulf Transmission Corporation and Registrant incorporated herein by reference to Exhibit 10(h) to Registrant's Form 10-K (File No. 000-08788), for the period ended June 30, 2010.
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	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.
10.26	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.
10.27	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.
10.28	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.

10.29	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.
10.30	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.
10.31	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.
10.32	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 Exhibits 10.1, 10.2, 10.3, 10.4 and 10.5, respectively, of Registrant's Form 8-K (File No. 000-08788) dated August 16, 2011.
10.33	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, 2012.
10.34	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.
10.35	Form of Notice of Performance Shares Award is filed herewith.
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.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Database
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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, 2014, 2013 and 2012;

(iii) Consolidated Statements of Cash Flows for the years ended June 30, 2014, 2013 and 2012;

(iv) Consolidated Balance Sheets as of June 30, 2014 and 2013;

(v) Consolidated Statements of Changes in Shareholders' Equity for the years ended June 30, 2014, 2013 and 2012;

(vi) Notes to Consolidated Financial Statements;

(vii) Schedule II – Valuation and Qualifying Accounts for the years ended June 30, 2014, 2013 and 2012.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospects for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

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 26th day of August, 2014.

DELTA NATURAL GAS COMPANY, INC.

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

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 26, 2014

(ii) Principal Financial Officer:

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 26, 2014

(iii) Principal Accounting Officer:

/s/Matthew D. Wesolosky (Matthew D. Wesolosky)	Vice President - Controller	August 26, 2014

(iv) A Majority of the Board of Directors:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 26, 2014
/s/Sandra C. Gray (Sandra C. Gray)	Director	August 26, 2014
/s/Edward J. Holmes (Edward J. Holmes)	Director	August 26, 2014
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 26, 2014
/s/Lewis N. Melton (Lewis N. Melton)	Director	August 26, 2014
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 26, 2014
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 26, 2014

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, 2014 and 2013, 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, 2014. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Delta Natural Gas Company, Inc. and subsidiaries as of June 30, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2014, 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, present fairly, in all material respects, the information set forth therein.

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, 2014, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated August 26, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 26, 2014

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Year Ended June 30,	2014	2013	2012
Operating Revenues			
Regulated revenues	$ 57,054,180	$ 46,427,203	$ 42,655,378
Non-regulated revenues	38,791,691	34,237,634	31,422,944
Total operating revenues	$ 95,845,871	$ 80,664,837	$ 74,078,322
Operating Expenses			
Regulated purchased natural gas	$ 27,215,425	$ 17,825,487	$ 15,703,114
Non-regulated purchased natural gas	29,059,426	26,011,164	23,380,426
Operation and maintenance	15,495,537	15,208,162	13,651,689
Depreciation and amortization	6,147,618	6,092,651	5,923,775
Taxes other than income taxes	2,324,426	2,338,694	2,154,090
Total operating expenses	$ 80,242,432	$ 67,476,158	$ 60,813,094
Operating Income	$ 15,603,439	$ 13,188,679	$ 13,265,228
Other Income and Deductions, Net	$ 201,462	$ 150,816	$ 75,170
Interest Charges			
Interest on long-term debt	$ 2,373,024	$ 2,438,325	$ 2,984,413
Other interest (income) expense	51,563	(822,190)	984,612
Amortization of debt expense	246,600	253,800	329,231
Total interest charges	$ 2,671,187	$ 1,869,935	$ 4,298,256
Net Income Before Income Taxes	$ 13,133,714	$ 11,469,560	$ 9,042,142
Income Tax Expense	4,858,586	4,268,784	3,258,144
Net Income	$ 8,275,128	$ 7,200,776	$ 5,783,998
Earnings Per Common Share (Note 11)			
Basic and Diluted	$ 1.19	$ 1.05	$ .85
Dividends Declared Per Common Share	$ .76	$ .72	$ .70

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,	2014	2013	2012
Cash Flows From Operating Activities			
Net income	$ 8,275,128	$ 7,200,776	$ 5,783,998
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	6,420,525	6,428,051	6,334,647
Deferred income taxes and investment tax credits	(515,492)	1,959,741	2,513,400
Change in cash surrender value of officer's life insurance	(67,722)	(27,300)	153
Share-based compensation	1,111,966	921,709	712,144
Excess tax deficiency from share-based compensation	(8,967)	(8,946)	—
(Increase) decrease in assets			
Accounts receivable	2,216,925	(841,574)	(1,407,711)
Natural gas in storage	(1,644,186)	1,451,494	(121,547)
Deferred natural gas cost	3,197,921	(536,552)	(7,581)
Materials and supplies	(288,597)	9,256	(51,724)
Prepayments	(1,253,798)	893,490	(2,606,809)
Other assets	11,556	(177,919)	(548,470)
Increase (decrease) in liabilities			
Accounts payable	169,226	2,725,470	(3,518,540)
Accrued taxes	83,528	(2,757,561)	2,695,526
Asset retirement obligations	(553,612)	(493,946)	1,085,920
Other liabilities	185,805	(3,189,770)	2,650,640
Net cash provided by operating activities	$ 17,340,206	$ 13,556,419	$ 13,514,046
Cash Flows From Investing Activities			
Capital expenditures	$ (8,077,642)	$ (7,179,473)	$ (7,337,115)
Proceeds from sale of property, plant and equipment	268,082	131,545	183,678
Other	(60,000)	(60,000)	141,530
Net cash used in investing activities	$ (7,869,560)	$ (7,107,928)	$ (7,011,907)

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,	2014	2013	2012
Cash Flows From Financing Activities			
Dividends on common shares	$ (5,289,911)	$ (4,951,002)	$ (4,762,257)
Issuance of common shares	595,249	587,359	697,775
Debt issuance costs	—	—	(107,904)
Issuance of long-term debt	—	—	58,000,000
Excess tax benefit from share-based compensation	39,472	35,112	21,563
Repayment of long-term debt	(1,500,000)	(1,500,000)	(57,951,006)
Borrowings on bank line of credit	691,157	—	17,697,829
Repayment of bank line of credit	(691,157)	—	(17,697,829)
Net cash used in financing activities	$ (6,155,190)	$ (5,828,531)	$ (4,101,829)
Net Increase in Cash and Cash Equivalents	$ 3,315,456	$ 619,960	$ 2,400,310
Cash and Cash Equivalents, Beginning of Year	10,360,462	9,740,502	7,340,192
Cash and Cash Equivalents, End of Year	$ 13,675,918	$ 10,360,462	$ 9,740,502
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	$ 2,436,435	$ 2,509,962	$ 3,795,590
Income taxes (net of refunds)	$ 5,819,956	$ 1,573,321	$ 1,011,138
Significant non-cash transactions			
Accrued capital expenditures	$ 328,638	$ 301,679	$ 336,543
Loss on extinguishment of debt recognized as a regulatory asset (Note 10)	$ —	$ —	$ 1,896,000

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,	2014	2013
Assets		
Current Assets		
Cash and cash equivalents	$ 13,675,918	$ 10,360,462
Accounts receivable, less accumulated allowances for doubtful accounts of $360,000 and $536,000 in 2014 and 2013, respectively	6,681,964	8,700,982
Natural gas in storage, at average cost (Notes 1 and 16)	7,125,499	5,481,313
Deferred natural gas costs (Notes 1 and 14)	724,923	3,922,844
Materials and supplies, at average cost	574,699	561,270
Prepayments	3,491,257	1,987,855
Total current assets	$ 32,274,260	$ 31,014,726
Property, Plant and Equipment	$ 229,367,319	$ 223,545,925
Less - Accumulated provision for depreciation	(93,551,799)	(88,429,625)
Net property, plant and equipment	$ 135,815,520	$ 135,116,300
Other Assets		
Cash surrender value of life insurance (face amount of $948,000 and $945,000 in 2014 and 2013, respectively)	$ 402,147	$ 334,425
Prepaid pension (Note 6)	3,291,974	2,679,864
Regulatory assets (Note 1)	13,198,199	13,770,011
Unamortized debt expense (Notes 1 and 10)	90,304	97,104
Other non-current assets	952,757	917,585
Total other assets	$ 17,935,381	$ 17,798,989
Total assets	$ 186,025,161	$ 183,930,015

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,	2014	2013
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 6,706,021	$ 7,417,789
Current portion of long-term debt (Note 10)	1,500,000	1,500,000
Accrued taxes	1,553,670	1,433,666
Customers' deposits	593,010	646,375
Accrued interest on debt	120,712	132,560
Accrued vacation	752,905	730,867
Deferred income taxes	39,718	1,339,287
Other liabilities	591,606	435,064
Total current liabilities	$ 11,857,642	$ 13,635,608
Long-Term Debt (Note 10)	$ 53,500,000	$ 55,000,000
Long-Term Liabilities		
Deferred income taxes	$ 40,537,879	$ 39,623,563
Investment tax credits	24,600	40,600
Regulatory liabilities (Note 1)	1,165,260	1,252,629
Asset retirement obligations (Note 4)	3,260,721	3,547,441
Other long-term liabilities	950,707	824,759
Total long-term liabilities	$ 45,939,167	$ 45,288,992
Commitments and Contingencies (Note 13)		
Total liabilities	$ 111,296,809	$ 113,924,600
Shareholders' Equity		
Common shares ($1.00 par value), 20,000,000 shares authorized; 6,942,758 and 6,864,253 shares outstanding at June 30, 2014 and June 30, 2013, respectively	$ 6,942,758	$ 6,864,253
Premium on common shares	47,182,338	45,523,123
Retained earnings	20,603,256	17,618,039
Total shareholders' equity	$ 74,728,352	$ 70,005,415
Total liabilities and shareholders' equity	$ 186,025,161	$ 183,930,015

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, 2014			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415
Net income	—	—	8,275,128	8,275,128
Issuance of common shares	28,809	566,440	—	595,249
Issuance of common shares under the incentive compensation plan	49,696	299,930	—	349,626
Share-based compensation expense	—	762,340	—	762,340
Tax benefit from share-based compensation	—	30,505	—	30,505
Dividends on common shares	—	—	(5,289,911)	(5,289,911)
Balance, end of year	$ 6,942,758	$ 47,182,338	$ 20,603,256	$ 74,728,352

	Year Ended June 30, 2013			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,803,941	$ 44,048,201	$ 15,368,265	$ 66,220,407
Net income	—	—	7,200,776	7,200,776
Issuance of common shares	28,436	558,923	—	587,359
Issuance of common shares under the incentive compensation plan	31,876	232,226	—	264,102
Share-based compensation expense	—	657,607	—	657,607
Tax benefit from share-based compensation	—	26,166	—	26,166
Dividends on common shares	—	—	(4,951,002)	(4,951,002)
Balance, end of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415

	Year Ended June 30, 2012			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,732,344	$ 42,688,316	$ 14,346,524	$ 63,767,184
Net income	—	—	5,783,998	5,783,998
Issuance of common shares	38,929	658,846	—	697,775
Issuance of common shares under the incentive compensation plan	32,668	304,373	—	337,041
Share-based compensation expense	—	375,103	—	375,103
Tax benefit from share-based compensation	—	21,563	—	21,563
Dividends on common shares	—	—	(4,762,257)	(4,762,257)
Balance, end of year	$ 6,803,941	$ 44,048,201	$ 15,368,265	$ 66,220,407

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 gas in the open market. We also transport natural gas on behalf of local producers and customers not on our distribution system and sell liquids extracted from natural gas in our storage field and our pipeline systems. 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.

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)	2014	2013
Regulated segment		
Distribution, transmission and storage	203,969	197,251
General, miscellaneous and intangibles	22,421	22,009
Construction work in progress	381	1,711
Total regulated segment	226,771	220,971
Non-regulated segment	2,596	2,575
Total property, plant and equipment	229,367	223,546

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 2.8%, 2.9% and 2.9% of average depreciable plant for 2014, 2013 and 2012, respectively.

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 Sheet. When depreciable utility plant and equipment is retired any related removal costs incurred are charged against the regulatory liability.

We have a pipe replacement program approved by the Kentucky Public Service Commission, which allows us to adjust rates annually to earn a return on capital expenditures for the replacement of pipe and related facilities incurred subsequent to the test year in our most recent rate case. 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 2014, 2013 or 2012.

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 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.

Revenue and Accounts Receivable

Revenues and accounts receivable arise primarily from sales of natural gas to customers and from transportation services for others. We bill our customers on a monthly meter reading cycle. 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 and gas costs include the following:

(000)	2014	2013
Unbilled revenues ($)	1,788	1,435
Unbilled gas costs ($)	622	390
Unbilled volumes (Mcf)	63	47

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

Provisions for doubtful accounts are recorded 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.

Excise Taxes

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

Regulated Purchased Natural Gas Expense

Our regulated natural gas rates include a gas cost recovery clause 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.

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

($000)	2014	2013
Regulatory assets		
Current assets		
Deferred natural gas costs	725	3,923
Other assets		
Conservation/efficiency program expenses	164	198
Loss on extinguishment of debt	3,149	3,389
Asset retirement obligations	4,377	3,788
Accrued pension	5,508	6,369
Regulatory case expenses	—	26
Total other assets	13,198	13,770
Total regulatory assets	13,923	17,693
Regulatory liabilities		
Long-term liabilities		
Accrued cost of removal on long-lived assets	355	328
Regulatory liability for deferred income taxes	810	925
Total regulatory liabilities	1,165	1,253

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 32 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 fully 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) New Accounting Pronouncements

In December, 2011, the Financial Accounting Standards Board issued guidance requiring additional disclosure of the effect or potential effect of financial instruments and derivative instruments which have rights of setoff where an entity offsets the assets and liabilities of such instruments. The guidance, effective for our quarter ending December 31, 2013, did not require any additional disclosures with respect to our results of operations, financial position or cash flows, as we have no such financial instruments or derivative instruments.

In September, 2013, the Internal Revenue Service ("IRS") issued final regulations regarding the tax treatment of amounts paid to acquire, produce or improve tangible property, which update temporary regulations issued by the IRS in December, 2011. In 2014, the IRS plans to issue further guidance for specific industry sectors, including natural gas. The final regulations are effective for our tax year beginning July 1, 2014; however, we do not expect compliance with the final regulations and industry specific guidance to have a material impact on our results of operations, financial position or cash flows.

In May, 2014, the Financial Accounting Standards Board issued guidance revising the principles and standards for revenue recognition. The standard creates a framework for recognizing revenue to improve comparability of revenue recognition practices across entities and industries. The guidance is effective for our quarterly report ending September 30, 2017 and we are evaluating the methods of adoption allowed by the new standard and the effect the standard is expected to have on our results of operations, financial position and cash flow.

In June, 2014, the Financial Accounting Standards Board issued guidance on share-based payments where performance targets can be achieved subsequent to the requisite service period. The guidance, effective for our quarter ending September 30, 2015, is not expected to have a material impact on our results of operations, financial position or cash flows.

(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 are recorded at fair value and 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. In fiscal 2014, upon changing investment advisors for the supplemental retirement benefit trust, we adopted a new asset allocation model which resulted in the reallocation of assets in the trust. The fair value of the trust assets are as follows:

($000)	2014	2013
Trust assets		
Money market	44	9
U.S. equity securities	379	486
Foreign equity funds	167	—
U.S. fixed income funds	121	244
Foreign fixed income funds	53	—
Absolute return strategy mutual funds	143	—
	907	739

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. 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.

	2014		2013	
($000)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
4.26% Series A Notes	55,000	55,576	56,500	55,150

(4) Asset Retirement Obligations

Legal obligations

As of June 30, 2014 and 2013, 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 as asset retirement obligations on the accompanying Consolidated Balance Sheets:

($000)	2014	2013
Balance, beginning of year	3,547	3,824
Liabilities incurred	138	20
Liabilities settled	(567)	(616)
Accretion	258	267
Revisions in estimated cash flows	(115)	52
Balance, end of year	3,261	3,547

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 our regulator even though such costs do not represent legal obligations. In accordance with regulatory accounting standards, $355,000 and $328,000 of such accrued cost of removal was recorded as a regulatory liability on the accompanying Consolidated Balance Sheets as of June 30, 2014 and 2013, 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. Investment tax credits were deferred for certain periods prior to fiscal 1987 and are being amortized to income over the estimated useful lives of the applicable properties. We utilize the asset and liability method for accounting for income taxes, which requires that deferred income tax assets and liabilities be computed using tax rates that will be in effect when the book and tax temporary differences reverse. Changes in tax rates applied to accumulated deferred income taxes are not immediately recognized in operating results because of ratemaking treatment. A regulatory liability has been established to recognize the regulatory obligation to refund these excess deferred taxes through customer rates. The current portion of the net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in long-term liabilities 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)	2014	2013
Deferred Tax Liabilities		
Current		
Deferred natural gas cost	(275)	(1,459)
Prepaid expenses	(359)	(304)
	(634)	(1,763)
Non-Current		
Accelerated depreciation	(36,903)	(36,004)
Pension	(1,240)	(908)
Regulatory assets - asset retirement obligations	(820)	(736)
Regulatory assets - loss on extinguishment of debt	(1,196)	(1,287)
Regulatory assets - unrecognized accrued pension	(2,091)	(2,418)
Regulatory liabilities	(1,268)	(1,268)
Other	(954)	(1,040)
	(44,472)	(43,661)
Total deferred tax liabilities	(45,106)	(45,424)
Deferred Tax Assets		
Current		
Accrued employee benefits	405	313
Bad debt reserve	99	58
Other	90	53
	594	424
Non-Current		
Accrued employee benefits	992	855
Asset retirement obligations	1,176	1,284
Investment tax credits	15	25
Regulatory liabilities	1,570	1,610
Section 263(a) capitalized costs	105	182
Other	76	81
	3,934	4,037
Total deferred tax assets	4,528	4,461
Net accumulated deferred income tax liability	(40,578)	(40,963)

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

($000)	2014	2013	2012
Current			
Federal	4,532	1,940	525
State	842	390	220
Total	5,374	2,330	745
Deferred	(515)	1,939	2,513
Income tax expense	4,859	4,269	3,258

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

(%)	2014	2013	2012
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)	(0.2)	(0.3)
Other differences, net	(0.9)	(0.6)	(1.7)
Effective income tax rate	37.0	37.2	36.0

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, 2014, we did not have any unrecognized tax positions, which, if recognized, would impact the effective tax rate. As of June 30, 2013, the amount of unrecognized tax benefits, net of tax, which, if recognized, would impact the effective tax rate was $31,000. As of June 30, 2014, we have accrued interest of $5,000 on unrecognized tax positions. We recognized interest income of $4,000 and $1,000 on unrecognized tax positions on the Consolidated Statements of Income for 2014 and 2013, respectively.

The following is a reconciliation of our unrecognized tax benefits:

($000)	2014	2013
Balance, beginning of year	101	200
Gross decreases - tax positions in prior period	(37)	(99)
Balance, end of year	64	101

We file income tax returns in federal and Kentucky jurisdictions. Tax years previous to June 30, 2012 and June 30, 2011 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 plans to recognize the funded status of a defined benefit pension 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 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, 2014 and June 30, 2013, respectively, are as follows:

($000)	2014	2013
Change in Benefit Obligation		
Benefit obligation at beginning of year	23,521	23,278
Service cost	1,023	1,116
Interest cost	1,038	913
Actuarial (gain)/loss	1,810	(1,271)
Benefits paid	(1,009)	(515)
Benefit obligation at end of year	26,383	23,521
Change in Plan Assets		
Fair value of plan assets at beginning of year	26,201	20,971
Actual return on plan assets	3,983	2,945
Employer contributions	500	2,800
Benefits paid	(1,009)	(515)
Fair value of plan assets at end of year	29,675	26,201
Recognized Amounts		
Projected benefit obligation	(26,383)	(23,521)
Plan assets at fair value	29,675	26,201
Funded status	3,292	2,680
Net amount recognized as prepaid pension on the Consolidated Balance Sheets	3,292	2,680
Items Not Yet Recognized as a Component of Net Periodic Benefit Cost		
Prior service cost	(316)	(403)
Net loss	5,824	6,772
Amounts recognized as regulatory assets	5,508	6,369

The accumulated benefit obligation was $22,810,000 and $20,508,000 for 2014 and 2013, respectively.

($000)	2014	2013	2012
Components of Net Periodic Benefit Cost			
Service cost	1,023	1,116	921
Interest cost	1,038	913	921
Expected return on plan assets	(1,567)	(1,578)	(1,474)
Amortization of unrecognized net loss	342	615	200
Amortization of prior service cost	(86)	(86)	(87)
Net periodic benefit cost	750	980	481
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	4.25	4.5	4.0
Rate of compensation increase	4.0	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	4.5	4.0	5.25
Expected long-term return on plan assets	6.0	7.0	7.0
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 70% equity investments and 30% 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. 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. In June, 2013, upon changing investment advisors for our defined benefit plan, we adopted a new asset allocation model and in 2014 transitioned to our target allocations for plan assets and reallocated our investments from mutual funds to individual securities. Previously, each individual mutual fund had been selected based on its investment strategy, which approximates a specific asset class within our target allocations.

(%)	Target Allocations	Actual Allocations 2014	2013
Asset Class			
Cash and cash equivalents	3	3	3
Equity Securities			
U.S. equity securities	36	43	53
Foreign equity securities	20	19	11
Domestic real estate	5	5	6
	61	67	70
Fixed Income Securities			
U. S. fixed income security	15	12	27
Foreign fixed income security	8	6	—
	23	18	27
Other Securities			
Absolute return strategy mutual funds	13	12	—
	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 plan assets:

($000)	2014	Level 1	Level 2	Level 3
Asset Class				
Cash	1,026	1,026	—	—
Equity Securities				
U.S. equity securities	13,828	13,828	—	—
Foreign equity securities	5,706	5,706	—	—
	19,534	19,534	—	—
Fixed Income Securities				
U.S. treasury securities	593	593	—	—
High yield funds	1,773	1,773	—	—
Foreign bond funds	1,771	1,771	—	—
U.S. corporate bonds	714	—	714	—
Other	577	—	577	—
	5,428	4,137	1,291	—
Other Securities				
Absolute return strategy mutual funds	3,687	3,687	—	—
Total	29,675	28,384	1,291	—

($000)	2013	Level 1	Level 2	Level 3
Asset Class				
Cash	778	778	—	—
Exchange Traded Mutual Funds				
U.S. equity securities	14,191	14,191	—	—
Fixed income securities	6,969	6,969	—	—
Foreign equity securities	2,756	2,756	—	—
Domestic real estate securities	1,507	1,507	—	—
	25,423	25,423	—	—
Total	26,201	26,201	—	—

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 a $500,000 discretionary contribution to the defined benefit plan in fiscal 2014. We expect to contribute $500,000 to the defined benefit plan in fiscal 2015.

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

($000)	
2015	3,099
2016	729
2017	735
2018	1,616
2019	1,503
2020 - 2024	7,384

Effective May 9, 2008, any employees hired on and after that date were not eligible to participate in our defined benefit plan. Freezing the defined benefit 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 plan described below.

Employee Savings Plan

We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 4% of the employee's annual compensation. 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 Savings Plan account. Company contributions are discretionary and subject to change with approval from our Board of Directors. For 2014, 2013 and 2012, our Savings Plan expense was $350,000, $313,000 and $325,000, 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 2014, 2013 and 2012 Delta contributed $60,000 each year to the trust. As of June 30, 2014 and 2013, the irrevocable trust assets are $907,000 and $739,000, 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 28,809, 28,436 and 38,929 shares in 2014, 2013 and 2012, respectively. We registered 400,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2014 there were approximately 93,000 shares available for issuance.

(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 primarily through forward purchase contracts. We mitigate price risk by efforts to balance supply and demand. For our regulated segment we have minimal price risk resulting from these forward natural gas purchases because we are permitted to pass these gas costs on to our regulated customers through the natural gas cost recovery rate mechanism, approved quarterly by the Kentucky Public Service Commission. 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, 2014 and June 30, 2013. The maximum amount borrowed during 2014 was $691,000. We did not borrow from the bank line of credit during 2013. The bank line of credit extends through June 30, 2015. The interest rate on the used line of credit is the London Interbank Offered Rate plus 1.15%. 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

In December, 2011, we refinanced and redeemed our 5.75% Insured Quarterly Notes ($38,450,000) and 7% Debentures ($19,410,000) from the proceeds of a private debt financing. Under the Note Purchase and Private Shelf Agreement we issued $58,000,000 of Series A Notes, for which the purchasers paid 100% of the face principal amount. Unamortized debt expense of $1,896,000 related to the 5.75% Insured Quarterly Notes and 7% Debentures was reclassified from unamortized debt expense to regulatory assets on the accompanying Consolidated Balance Sheet. The $1,896,000 regulatory asset representing the loss on extinguishment of the 5.75% Insured Quarterly Notes and 7% Debentures, combined with $1,872,000 of unamortized loss on extinguishment of debt recognized from prior refinancings, will be amortized over the life of the 4.26% Series A Notes consistent with treatment approved by the Kentucky Public Service Commission.

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)	
2015	1,500
2016	1,500
2017	1,500
2018	1,500
Thereafter	49,000
Total long-term debt	55,000

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. At June 30, 2014 and 2013, the unamortized balance was $3,240,000 and $3,486,000, respectively. Loss on extinguishment of debt of $3,149,000 and $3,389,000 included in the above has been deferred as a regulatory asset and is being amortized over the term of the related debt consistent with regulatory accounting 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 share:

	2014	2013	2012
Numerator - Basic and Diluted ($000)			
Net income	8,275	7,201	5,784
Dividends paid	(5,290)	(4,951)	(4,762)
Undistributed earnings	2,985	2,250	1,022
Allocated to common shares:			
Percentage allocated to common shares (a)	99.4%	99.4%	99.6%
Undistributed earnings	2,966	2,238	1,018
Dividends paid	5,263	4,930	4,747
Net income available to common shares	8,229	7,168	5,765
Denominator - Basic and Diluted			
Weighted average common shares (b)	6,918,725	6,843,455	6,777,186
Net Income per Common Share - Basic and Diluted ($)	1.19	1.05	0.85

(a) Percentage allocated to weighted average common shares outstanding:

Common shares outstanding	6,918,725	6,843,455	6,777,186
Unvested participating shares outstanding (c)	44,750	38,417	28,082
Total	6,963,475	6,881,872	6,805,268
Percentage allocated to common shares	99.4%	99.4%	99.6%

(b) Under our Incentive Compensation Plan, recipients of performance share awards receive unvested non-participating shares, as further discussed in Note 17 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 in (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, 2014, 2013 and 2012.

(c) Certain awards under our shareholder approved incentive compensation plan, as further discussed in Note 17 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. There were no antidilutive shares in 2014, 2013 and 2012. There were 74,000, 68,000 and 48,000 unvested participating shares outstanding as of June 30, 2014, 2013 and 2012, 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, $71,000 and $70,000 for the years ended June 30, 2014, 2013 and 2012, 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 or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $4.2 million would be paid in addition to continuation of specified benefits for up to five years. Additionally, upon a change in control, all unvested shares awarded under our Incentive Compensation Plan, as further discussed in Note 17 of the Notes to Consolidated Financial Statements, would immediately vest.

Our June 30, 2012 Consolidated Income Statement included the accrual of $877,000 of interest expense related to an assessment of a license tax. The assessment was resolved in 2013 and the previously accrued interest was reversed.

We are not a party to any material pending legal proceedings.

We have entered into a forward purchase agreement for natural gas beginning in July, 2014 and expiring in December, 2014. The agreement requires us to purchase minimum amounts of natural gas throughout the term of the agreements. The agreement is established in the normal course of business to ensure adequate natural gas supply to meet our customers' natural gas requirements. The agreement has an aggregate minimum purchase obligation of $140,000 for our fiscal year ending June 30, 2015.

(14) Regulatory Matters

The Kentucky Public Service Commission exercises regulatory authority over our retail natural gas distribution and transportation services. Their regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas and transportation services. They have 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. 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 that would have a material impact on our results of operations, financial position or cash flows.

We have a pipe replacement program which 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.

The Kentucky Public Service Commission allows us a natural gas cost recovery clause, which 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 clause, 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.

Additionally, we have a weather normalization provision in our tariffs, approved by the Kentucky Public Service Commission, which allows us to adjust our rates to residential and small non-residential customers to reflect variations from thirty year average weather for our December through April billing cycles. These adjustments to customer bills are made on a real time basis such that there is no lag in collecting from or refunding to customers the related dollar amounts.

The Kentucky Public Service Commission allows us a conservation and efficiency program for our residential customers. The program provides for us to perform energy audits, promote conservation awareness and provide rebates on the purchase of certain high-efficiency appliances. The program helps to align our interests with our residential customers' interests by reimbursing us for the margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

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

(15) Segment Information

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

In our non-regulated segment, three customers each provided more than 5% of our operating revenues. Our largest customer provided approximately $12,569,000 of nonregulated revenues during 2014. Our second largest customer provided approximately $9,494,000, $17,866,000 and $12,450,000 of non-regulated revenues during 2014, 2013 and 2012, respectively. Our third largest customer provided approximately $5,206,000, $5,390,000 and $6,815,000 of non-regulated revenues during 2014, 2013 and 2012, respectively. There is no assurance that revenues from these customers will continue at these levels.

We purchased approximately 96% and 98% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services in 2014 and 2013, respectively. In 2012, we purchased approximately 99% of our natural gas from Atmos Energy Marketing and M & B Gas Services.

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)	2014	2013	2012
Operating Revenues			
Regulated			
External customers	57,054	46,427	42,655
Intersegment	4,041	4,145	3,704
Total Regulated	61,095	50,572	46,359
Non-regulated			
External customers	38,792	34,238	31,423
Eliminations for intersegment	(4,041)	(4,145)	(3,704)
Total operating revenues	95,846	80,665	74,078
Operating Expenses			
Regulated			
Purchased natural gas	27,215	17,825	15,703
Depreciation and amortization	6,068	6,023	5,871
Other	15,285	14,701	13,909
Total regulated	48,568	38,549	35,483
Non-regulated			
Purchased natural gas	29,059	26,011	23,380
Depreciation and amortization	80	70	53
Other	6,576	6,990	5,601
Total non-regulated	35,715	33,071	29,034
Eliminations for intersegment	(4,041)	(4,145)	(3,704)
Total operating expenses	80,242	67,476	60,813
Other Income and Deductions, Net			
Regulated	183	151	77
Non-regulated	18	—	(2)
Total other income and deductions, net	201	151	75
Interest Charges			
Regulated	2,633	2,688	3,366
Non-regulated	38	(818)	932
Total interest charges	2,671	1,870	4,298
Income Tax Expense			
Regulated	3,907	3,676	2,772
Non-regulated	952	593	486
Total income tax expense	4,859	4,269	3,258
Net Income			
Regulated	6,407	5,970	4,990
Non-regulated	1,868	1,231	794
Total net income	8,275	7,201	5,784
Assets			
Regulated	181,530	177,662	174,454
Non-regulated	4,495	6,268	8,441
Total assets	186,025	183,930	182,895
Capital Expenditures			
Regulated	8,078	6,983	7,163
Non-regulated	—	196	174
Total capital expenditures	8,078	7,179	7,337

(16) Insurance Proceeds

In September, 2011, we received $300,000 of insurance proceeds relating to a natural gas inventory adjustment recorded in fiscal 2009 for the Company's underground natural gas storage field. These proceeds are included in operation and maintenance in the 2012 Consolidated Statement of Income.

(17) 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 which may be issued pursuant to the Plan may not exceed in the aggregate 1,000,000 shares. As of June 30, 2014, approximately 794,000 shares of common stock were available for issuance under the Plan. Shares of common stock may be issued from authorized but unissued shares, shares reacquired by us or shares that we purchase in the open market.

Compensation expense for share-based compensation is recorded in the non-regulated segment and included 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. Our share-based compensation expense was $1,112,000, $922,000 and $712,000 for 2014, 2013 and 2012, respectively.

Tax benefits of $31,000 and $26,000 were recognized as a premium on common shares on our 2014 and 2013 Consolidated Balance Sheets, respectively, which decreased our taxes payable as the deduction for income tax purposes exceeds the compensation expense recognized for financial reporting purposes. The excess tax benefits can be utilized to offset tax deficiencies related to share-based compensation in subsequent periods.

Stock Awards

In 2014, 2013 and 2012, common stock was awarded to virtually all Delta employees and directors having grant date fair values of $350,000 (17,000 shares), $264,000 (12,000 shares) and $337,000 (22,000 shares), respectively. 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 2014, 2013 and 2012, performance shares were awarded to the Company's executive officers having grant date fair values of $801,000 (39,000 shares) and $844,000 (39,000 shares) and $552,000 (36,000 shares), respectively. The performance share awards 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. 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.

As of June 30, 2014 the performance objectives for the performance shares awarded in 2014 have been satisfied and subject to further limitations of the plan, up to 39,000 unvested shares will be issued to the recipients, subject to a service condition whereby a recipient of the award shall vest in one-third increments each year beginning August 31, 2013 and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. The performance objectives for the performance shares awarded in 2013 were met and 39,000 unvested shares were issued on August 31, 2013, of which 26,000 shares remain unvested as of June 30, 2014.

For 2014, 2013 and 2012, compensation expense related to the performance shares was $762,000, $658,000 and $375,000, respectively. Compensation expense of $469,000 is expected to be recognized between 2015 and 2017 for the unvested shares.

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, 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, 2014 is 1.6 years.

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, 2013	67,668	18.85
Granted (a)	39,000	20.53
Vested	(32,668)	(17.62)
Unvested shares at June 30, 2014	74,000	20.28

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

(18) Quarterly Financial Data (Unaudited)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2014				
September 30	$ 13,041,272	$ 692,098	$ 79,409	$ 0.01
December 31	25,810,664	5,624,971	3,134,729	0.45
March 31	40,435,516	8,886,123	5,173,624	0.74
June 30	16,558,419	400,247	(112,634)	(0.01)
Fiscal 2013				
September 30	$ 11,452,315	$ 415,946	$ (158,903)	$ (0.02)
December 31	22,106,691	4,967,855	3,249,376	0.47
March 31	31,133,349	7,323,064	4,242,677	0.62
June 30	15,972,482	481,814	(132,374)	(0.02)

(19) Subsequent Events

In August, 2014, 22,000 shares of common stock were awarded to virtually all Delta employees and directors having a grant date fair value of $443,000. Additionally, in August, 2014, performance shares were awarded to the Company's executive officers. The performance share awards vest only if the performance objective of the awards is met, which is based on the Company's fiscal 2015 audited earnings per share, before any cash bonuses or share-based compensation. Subject to further limitations described in the Plan, all performance shares paid shall be in the form of unvested shares, which contain a service condition whereby recipients of the awards shall vest in one-third increments each year beginning on August 31, 2015, and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. The maximum number of shares which could be issued under the performance awards is 39,000, having a grant date fair value of $772,980.

SCHEDULE II

DELTA NATURAL GAS COMPANY, INC.

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED JUNE 30, 2014, 2013 and 2012

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, 2014	$ 536,255	$ 107,131	$ 225,502	$ 508,888	$ 360,000
June 30, 2013	157,000	496,512	140,178	257,435	536,255
June 30, 2012	190,000	127,891	168,204	329,095	157,000

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

	2014	2013	2012	2011	2010
Earnings					
Net income	$ 8,275,128	$ 7,200,776	$ 5,783,998	$ 6,364,895	$ 5,651,817
Provisions for income taxes (a)	4,858,586	4,268,784	3,258,144	3,759,607	3,192,285
Fixed charges	2,694,187	2,770,935	4,321,256	4,112,798	4,194,192
Total	$ 15,827,901	$ 14,240,495	$ 13,363,398	$ 14,237,300	$ 13,038,294
Fixed Charges					
Interest on debt (a)	$ 2,424,587	$ 2,493,135	$ 3,969,025	$ 3,701,535	$ 3,781,929
Amortization of debt	246,600	253,800	329,231	387,263	387,263
One third of rental expense	23,000	24,000	23,000	24,000	25,000
Total	$ 2,694,187	$ 2,770,935	$ 4,321,256	$ 4,112,798	$ 4,194,192
Ratio of earnings to fixed charges	5.87x	5.14x	3.09x	3.46x	3.11x

(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 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

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

I, Glenn R. Jennings, certify that:

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

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

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

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

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

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

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

DATE: August 26, 2014

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

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

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

I, John B. Brown, certify that:

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

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

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

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

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

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

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

DATE: August 26, 2014

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

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

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: August 26, 2014

/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, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: August 26, 2014

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Exhibit 13-3

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, 2015

☐ **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 ☐

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. $149,020,746.

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 25, 2015, Delta Natural Gas Company, Inc. had outstanding 7,027,941 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, 2015, is incorporated by reference in Part III of this Report.

TABLE OF CONTENTS

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, “2015”, “2014” and “2013” 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 use 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.

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. Financial Statements and Supplementary Data and under “Regulatory Matters” in Item 1. Business.

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 2015, 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 larger 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 and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most 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.

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, 2015, 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 Atmos Energy Marketing ("Atmos") for our Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. We are not obligated to purchase any minimum quantities from Atmos or 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 for the indices that relate to the pipelines through which the natural gas will be transported, 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 Atmos 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, 2015, approximately 48% of our regulated natural gas supply was purchased under our agreements with Atmos.

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, 2015, approximately 51% 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. We intend 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 2015, Tennessee transported for us a total of 1,705,000 Mcf, or approximately 38% 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 Atmos, 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 2015, Columbia Gas and Columbia Gulf transported for us a total of 428,000 Mcf, or approximately 10% of our regulated natural gas supply, under all of our agreements with them. Our transportation agreements with Columbia Gas and Columbia Gulf extend through October 2015, which we intend to renew. After 2015, our agreements with Columbia Gas and Columbia Gulf continue on a year-to-year basis unless terminated by one of the parties, but 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 2015 constituted approximately 51% of our regulated gas supply. We are not a party to any of these separate transportation agreements on Columbia Gulf.

We have no direct agreement with Texas Eastern. However, Atmos has an arrangement with Texas Eastern to transport the natural gas to us that we purchase from Atmos to supply our customers' requirements in specific geographic areas. In our fiscal year ended June 30, 2015, Texas Eastern transported approximately 23,000 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 43,000 Mcf from Vinland during fiscal 2015. The price for the natural gas we purchase from Vinland is based on the index price of spot 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 2015, the natural gas we purchased from Vinland constituted 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 tariffs and the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas distribution and transportation services. They have historically utilized cost-of-service ratemaking where our base rates are established to recover normal operating expenses, exclusive of gas costs, and a reasonable rate of return. 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 positions 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 margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in five 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.

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 larger non-regulated customers can obtain their natural gas supply by purchasing directly from interstate suppliers, local producers or marketers and arranging for alternate transportation of the 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, 2015, approximately 96% 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 2015. Atmos provided approximately $7,127,000, $5,206,000 and $5,390,000 of non-regulated revenues during 2015, 2014 and 2013, respectively. Greystone, LLC provided approximately $17,852,000 and $12,569,000 of non-regulated revenues during 2015 and 2014. 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. Properties further describes Enpro's oil and natural gas leases and production properties. Enpro produced a total of 94,000 Mcf of natural gas during 2015 which was approximately 1% 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 and the pricing for any such liquids as determined by a national unregulated market. In our fiscal year ended June 30, 2015, approximately 3% 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 unregulated sales activities may have longer terms or multiple month purchase commitments. In our fiscal year ended June 30, 2015, 91% of our non-regulated natural gas supply was purchased under our agreement with Midwest.

Additionally, our non-regulated segment purchases natural gas from Atmos as needed. This spot purchasing arrangement is pursuant to an agreement with Atmos containing an “evergreen” clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from Atmos under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing 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, 2015, approximately 8% of our non-regulated natural gas supply was purchased under our agreement with Atmos.

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.

Capital Expenditures

Capital expenditures during 2015 were $9.0 million and for 2016 are estimated to be $7.5 million. Our expenditures include system extensions as well as the replacement and improvement of existing transmission, distribution, gathering, storage and general facilities.

Financing

Our capital expenditures and operating cash requirements are 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, 2015.

Our current bank line of credit extends through June 30, 2017 and will be available to meet capital expenditure and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

We currently have long-term debt of $53,500,000 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, 2015, we had 142 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,	2015	2014	2013	2012	2011
Average Regulated Customers Served	34,384	34,490	34,701	34,860	35,413
Operating Revenues ($000) (a)					
Regulated revenues					
Natural gas sales	46,828	51,542	41,202	37,660	43,671
Natural gas transportation	9,366	9,163	9,037	8,375	8,500
Other	356	390	333	324	303
Total regulated revenues	56,550	61,095	50,572	46,359	52,474
Non-regulated revenues	33,507	38,792	34,238	31,423	34,343
Intersegment eliminations (b)	(3,869)	(4,041)	(4,145)	(3,704)	(3,777)
Total	86,188	95,846	80,665	74,078	83,040
System Throughput (Million Cu. Ft.) (a)					
Regulated					
Natural gas sales	3,261	3,351	3,057	2,448	3,167
Natural gas transportation	16,855	16,423	16,783	15,949	16,361
Total regulated throughput	20,116	19,774	19,840	18,397	19,528
Non-regulated	7,357	7,241	7,650	6,455	6,010
Intersegment eliminations (b)	(7,210)	(7,096)	(7,497)	(6,326)	(5,890)
Total	20,263	19,919	19,993	18,526	19,648
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	59	61	56	44	57
Lexington, Kentucky Degree Days					
Actual	4,964	4,855	4,667	3,797	4,725
Percent of 30 year average	110	107	104	83	103

(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.

WEATHER CONDITIONS MAY CAUSE OUR REVENUES TO VARY FROM YEAR TO YEAR.

Our revenues vary from year to year, depending on weather conditions. We estimate that approximately 74% of our annual natural gas sales are temperature sensitive. As a result, mild winter temperatures can cause a decrease in 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.

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 larger 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 by-passes in order to achieve lower prices for their natural gas and/or transportation services. Our larger customers who are in close proximity to alternative supply would be most likely to consider taking this action. This potential to by-pass our distribution and transportation systems creates a risk of the loss of large customers and thus could result in lower revenues and profits.

ACTIONS BY OUR REGULATORS COULD DECREASE FUTURE PROFITABILITY.

We are regulated by the Kentucky Public Service Commission. Our regulated segment generates a significant portion of our operating revenues. We face the risk that the Kentucky Public Service Commission may fail to grant us adequate and timely rate increases, may decrease our rates or may take other actions that would cause a reduction in our income from operations, such as limiting our ability to pass on to our customers our costs of natural gas. Such regulatory actions would decrease our revenues and our profitability. Additionally, our consolidated financial statements reflect the application of regulatory accounting standards by our regulated segment. 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 income and consolidated financial statements.

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 unregulated market, and decreases in the price could result in a decrease in our non-regulated gross margins.

DERIVATIVES LEGISLATION COULD ADVERSELY AFFECT OUR ABILITY TO HEDGE RISKS ASSOCIATED WITH OUR BUSINESS OR OTHERWISE HAVE A MATERIAL AND ADVERSE EFFECT ON OUR FINANCIAL POSITION, RESULTS OF OPERATIONS OR CASH FLOWS.

As part of our risk management strategy, we currently use, and historically have used, forward commodity contracts, which meet the criteria of a derivative. The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") adopted a comprehensive framework for the regulation of over-the-counter swaps ("OTC swaps"). The Dodd-Frank Act divides regulatory authority over swap agreements between the SEC and the Commodity Futures Trading Commission ("CFTC") and requires that most OTC swaps be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. While the SEC and CFTC have adopted numerous regulations relating to OTC swaps, they are still in the process of rulemaking to address all of the requirements regarding OTC swaps under the Dodd-Frank Act. Current and future legal and regulatory requirements, restrictions and regulations imposed under the Dodd-Frank Act could increase the operational and transactional cost of derivatives contracts and could affect the number and/or creditworthiness of available counterparties. Our inability to enter into derivative contracts at favorable terms, or at all, could increase our operating expenses and our ability to hedge our business risks.

INTERSTATE AND OTHER PIPELINES DELTA INTERCONNECTS WITH CAN IMPOSE RESTRICTIONS ON THEIR PIPELINE.

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

FUTURE PROFITABILITY OF THE NON-REGULATED SEGMENT IS DEPENDENT ON A FEW INDUSTRIAL AND OTHER LARGE-VOLUME CUSTOMERS.

Our non-regulated customers are primarily industrial and other large-volume customers. Fluctuations in 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 NATURAL GAS SUPPLY, 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 unregulated market. A reduction in the quantity of liquids present in our natural gas supply, 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. Such cash funding obligations 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, the breakdown or failure of equipment or processes, the performance of pipeline and storage facilities below expected levels of capacity and efficiency, loss of 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, 2015 our Series A Notes permit us to pay up to an additional $23,634,000 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 that 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 and/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.

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. Business.

Through our wholly-owned subsidiary, Enpro, we produce natural gas as part of the non-regulated segment of our business. Enpro owns interests in oil and natural gas leases on 10,300 acres located in Bell, Knox and Whitley Counties. Thirty-five gas wells are producing from these properties. The remaining proved, developed natural gas reserves on these properties are estimated at 2.3 million Mcf. Also, Enpro owns the natural gas underlying 15,400 additional acres in Bell, Clay and Knox Counties. These properties have been leased to others for further drilling and development 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 94,000 Mcf of natural gas during fiscal 2015 from all the properties described in this paragraph.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

We are not currently a party to any 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.

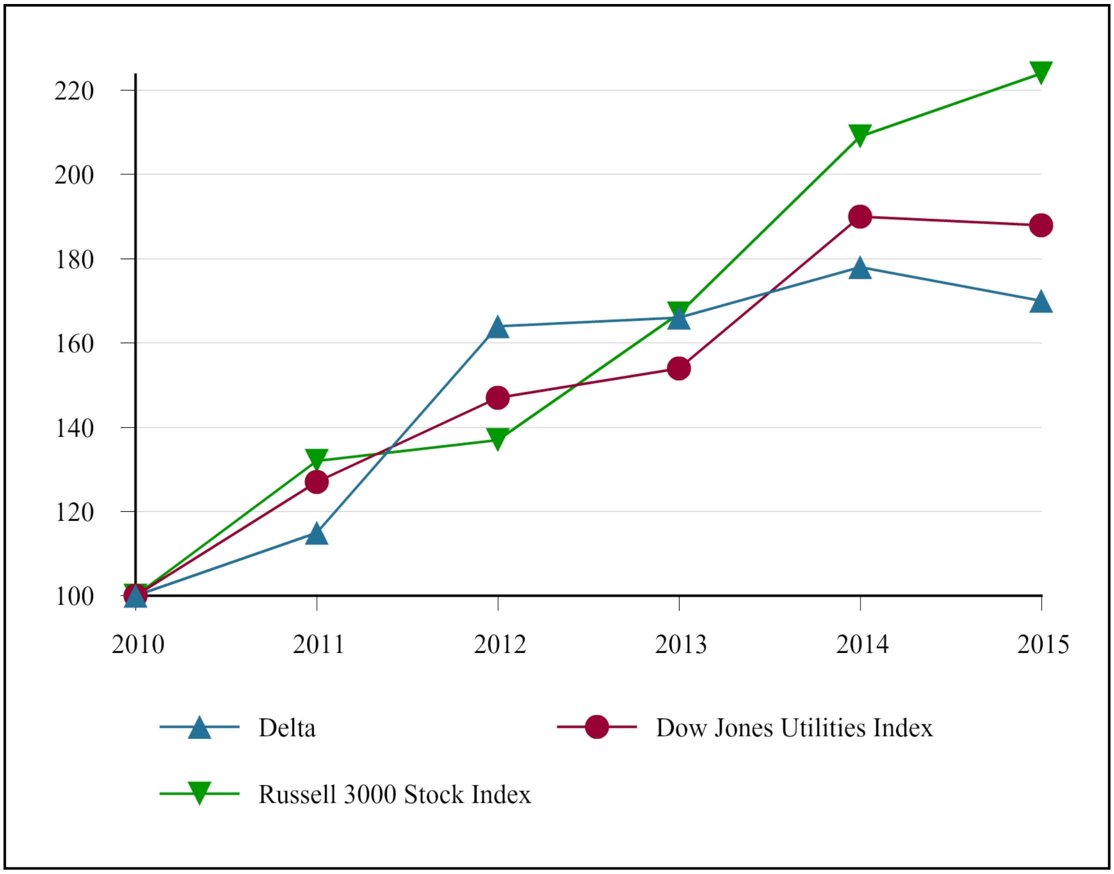
Our common stock is listed on NASDAQ and trades under the symbol “DGAS”. There were 1,432 record holders of our common stock as of August 24, 2015. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ stock market and the cash dividends declared per share.

Quarter	Range of Stock Prices ($) High	Low	Dividends Per Share ($)
Fiscal 2015			
First	22.58	19.50	.20
Second	21.54	19.50	.20
Third	21.39	19.10	.20
Fourth	20.84	19.39	.20
Fiscal 2014			
First	25.02	18.50	.19
Second	22.90	19.98	.19
Third	22.29	18.44	.19
Fourth	22.13	18.43	.19

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.

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, 2010 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.



	2010	2011	2012	2013	2014	2015
Delta	100	115	164	166	178	170
Dow Jones Utilities Index	100	127	147	154	190	188
Russell 3000 Stock Index	100	132	137	167	209	224

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,	2015	2014	2013	2012	2011
Summary of Operations ($)					
Operating revenues	86,188,238	95,845,871	80,664,837	74,078,322	83,040,251
Operating income	12,963,861	15,603,439	13,188,679	13,265,228	14,061,794
Net income (a)	6,496,081	8,275,128	7,200,776	5,783,998	6,364,895
Earnings per common share (a)					
Basic and diluted	.92	1.19	1.05	.85	.95
Cash dividends declared per common share	.80	.76	.72	.70	.68
Weighted Average Number of Common Shares					
Basic and Diluted	7,002,694	6,918,725	6,843,455	6,777,186	6,707,224
Diluted	7,002,694	6,918,725	6,843,455	6,777,186	6,712,804
Total Assets ($)	187,794,870	186,025,161	183,930,015	182,895,363	174,896,239
Capitalization ($)					
Common shareholders' equity	77,221,654	74,728,352	70,005,415	66,220,407	63,767,184
Long-term debt	52,000,000	53,500,000	55,000,000	56,500,000	56,751,006
Total capitalization	129,221,654	128,228,352	125,005,415	122,720,407	120,518,190
Short-Term Debt ($) (b)	1,500,000	1,500,000	1,500,000	1,500,000	1,200,000
Other Items ($)					
Capital expenditures	9,010,876	8,077,642	7,179,473	7,337,115	8,123,479
Total property, plant and equipment	236,780,490	229,367,319	223,545,925	217,172,542	211,409,336

(a) In 2012, $877,000 of interest expense was accrued relating to a tax assessment. In 2013, the assessment was resolved and the previously accrued interest was reversed.
(b) Includes current portion of long-term debt.

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

Overview of 2015 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 2015. 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 produces natural gas and sells liquids extracted from natural gas.

Consolidated income per common share of $0.92 for 2015 decreased, as compared to our consolidated income of $1.19 for 2014, due to decreased revenue, net of gas costs from the sale of natural gas and natural gas liquids by our non-regulated segment (as further discussed in Results of Operations).

Future Outlook

Future profitability of the regulated segment is contingent on the adequate and timely adjustment of the rates we charge our regulated customers. The Kentucky Public Service Commission sets these rates, and we monitor our need to file rate cases with the Kentucky Public Service Commission for a general rate increase for our regulated services. 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 2016. If natural gas prices increase, we would expect to experience a corresponding increase in our non-regulated gross margins related to our natural gas marketing activities. However, if natural gas prices decrease, we would expect a decrease in our non-regulated gross margins 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 unregulated market. We experienced a 46% decline this past year in the average sales price of natural gas liquids, which reduced consolidated net income by $0.08 per common share for 2015 as compared to 2014.

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, 2017 and permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit as of June 30, 2015 or June 30, 2014.

Cash and cash equivalents were $16,924,000 at June 30, 2015 compared with $13,676,000 at June 30, 2014 and $10,360,000 at June 30, 2013. These changes in cash and cash equivalents are summarized in the following table:

$(000)	2015	2014	2013
Provided by operating activities	18,746	17,340	13,557
Used in investing activities	(8,910)	(7,870)	(7,108)
Used in financing activities	(6,588)	(6,155)	(5,829)
Increase in cash and cash equivalents	3,248	3,315	620

In 2015, cash provided by operating activities increased $1,406,000 (8%), as compared to 2014, due to decreased cash paid for income taxes as a result of decreased earnings in the current year, which were partially offset by decreased cash received from the sale of natural gas liquids.

In 2014, cash provided by operating activities increased $3,783,000 (28%), as compared to 2013, due to increased cash received from customers as a result of increased sales, partially offset by increased amounts paid for natural gas.

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

In 2015 and 2014 there were no significant changes in cash used in financing activities, as compared to 2014 and 2013, 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, storage and general facilities. We expect our capital expenditures for fiscal 2016 to be approximately $7.5 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2015:

	Payments Due by Fiscal Year				
$(000)	2016	2017 - 2018	2019 - 2020	After 2020	Total
Interest payments (a)	2,297	4,299	4,043	18,259	28,898
Long-term debt (b)	1,500	3,000	3,000	46,000	53,500
Pension contributions (c)	500	1,000	1,000	4,500	7,000
Natural gas purchases (d)	440	150	—	—	590
Total contractual obligations (e)	4,737	8,449	8,043	68,759	89,988

(a) Our long-term debt, notes payable, customers' deposits and unrecognized tax positions all require interest payments. Interest payments are projected based on fiscal 2015 interest payments until the underlying obligation is satisfied. As of June 30, 2015, we have also accrued $5,000 of interest related to uncertain tax positions. These amounts have been excluded from the above table of contractual obligations as the timing of such payments is uncertain.

(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 plan through 2029, as recommended by our actuary.

(d) As of June 30, 2015, our non-regulated segment had forward purchase contracts for natural gas which had minimum purchase obligations that expire in December, 2016. 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 ($41,989,000), regulatory liabilities ($1,138,000), asset retirement obligations ($3,796,000) and deferred compensation ($977,000). 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 sets 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, 2015:

	Requirement	Actual
Tangible net worth	no less than $25,800,000	$76,127,000
Debt to capitalization ratio	no more than 70%	41%
Fixed charge coverage ratio	no less than 1.20x	8.00 x
Dividends paid	no more than $43,090,000	$19,455,000

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 rate-making 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.

Pension

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, 2015, 2014 and 2013, we recorded pension costs for our defined benefit retirement plan of $493,000, $750,000 and $980,000, 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, 2015, $7,391,000 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 6% for 2015 and was based on our targeted asset allocation assumption for 2015 of approximately 70% equity investments and approximately 30% 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. 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 4.25%, and various other assumptions, we estimate that our pension costs associated with our defined benefit retirement plan will increase from $493,000 in 2015 to $812,000 in 2016. Modifying the expected long-term rate of return on our pension plan assets by .25% would change pension costs for 2016 by approximately $74,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $107,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $113,000.

Unbilled Revenues and 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 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.

Asset Retirement Obligations

We have accrued asset retirement obligations for gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations is recorded at the time the obligations are incurred. We do not recognize asset retirement obligations relating to assets with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities accrete for the change in their present value, and the initial capitalized costs depreciate over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated operations, the accretion and depreciation are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement dates and the assumed credit-adjusted risk-free interest rates. Our asset retirement obligations are further discussed in Note 4 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as “estimates”, “attempts”, “expects”, “monitors”, “plans”, “anticipates”, “intends”, “continues”, “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 our natural gas supply 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. Risk Factors 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 margin can be derived directly from our Consolidated Statements of Income included in Item 8. Financial Statements and Supplemental Data, as follows:

($000)	2015	2014	2013
Operating revenues	86,188	95,846	80,665
Regulated purchased natural gas	(22,729)	(27,215)	(17,825)
Non-regulated purchased natural gas	(26,713)	(29,059)	(26,011)
Consolidated gross margins	36,746	39,572	36,829

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 an unregulated national market. Therefore, the prices that we pay for natural gas fluctuate with national supply and demand. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for discussion of our forward contracts.

In the following table we set forth variations in our gross margins for the last two 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)	2015 compared to 2014	2014 compared to 2013
Increase (decrease) in gross margins		
Regulated segment		
Natural gas sales	(228)	950
Natural gas transportation	203	126
Other	(34)	57
Intersegment elimination (a)	172	104
Total	113	1,237
Non-regulated segment		
Natural gas sales	(1,601)	1,053
Natural gas liquids	(1,111)	529
Other	(55)	28
Intersegment elimination (a)	(172)	(104)
Total	(2,939)	1,506
Increase (decrease) in consolidated gross margins	(2,826)	2,743
Percentage increase (decrease) in volumes		
Regulated segment		
Natural gas sales (Mcf)	(3)	10
Natural gas transportation (Mcf)	3	(3)
Non-regulated segment		
Natural gas sales (Mcf)	2	(5)
Natural gas liquids (gallons)	(1)	39

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

Heating degree days were 110% of the normal thirty year average temperatures for fiscal 2015, as compared with 107% and 104% of normal temperatures for 2014 and 2013, 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 2015, consolidated gross margins decreased $2,826,000 (7%), as compared to 2014, due to decreased non-regulated 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 unregulated market.

In 2014, consolidated gross margins increased $2,743,000 (7%), as compared to 2013, due to increased non-regulated and regulated gross margins of $1,506,000 and $1,237,000, respectively. Non-regulated gross margins increased due to the increased sales of the non-regulated segment's natural gas production inventory and increased sales of natural gas liquids extracted from the natural gas in our system. Regulated gross margins increased due to a 10% increase in volumes sold to our regulated customers as a result of colder weather and increased amounts billed through our pipe replacement program tariff. Partially offsetting these increases are decreased rates billed through our weather normalization tariff.

Operating Expenses

In 2015 and 2014, there were no significant changes in operation and maintenance, as compared to 2014 and 2013, respectively.

In 2015 and 2014, there were no significant changes in depreciation and amortization, as compared to 2014 and 2013, respectively.

In 2015, taxes other than income taxes increased $472,000 (20%) primarily due to an increase in property taxes resulting from an increase in the assessed value of our property.

In 2014, there were no significant changes in taxes other than income taxes, as compared to 2013.

Other Income and Deductions, Net

In 2015, other income and deductions, net decreased $176,000 (88%) due to a decrease in the earnings from the supplemental retirement trust and a decrease in interest received on the cash surrender value of our life insurance policies. The decrease in the earnings from the supplemental retirement trust was offset by a decrease in operating expense resulting from a corresponding change in the liability of the trust.

In 2014, there were no significant changes in other income and deductions, net, as compared to 2013.

Interest Charges

In 2015 and 2014, there were no significant changes in interest on long-term debt and amortization of debt expense, as compared to 2014 and 2013, respectively.

In 2015, there were no significant changes in other interest (income) expense, as compared to 2014.

In 2014, other interest (income) expense increased $874,000 (106%), as compared to 2013 due to a decrease in interest accrued in the prior year relating to a resolution of a tax assessment.

Income Tax Expense

In 2015, income tax expense decreased $967,000 (20%) due to a decrease in net income before income taxes. There were no significant changes in our effective tax rate for 2015, as compared to 2014.

In 2014, income tax expense increased $590,000 (14%) due to an increase in net income before income taxes. There were no significant changes in our effective tax rate for 2014, as compared to 2013.

Basic and Diluted Earnings Per Common Share

For 2015 and 2014, our basic and diluted earnings per common share changed, as compared to 2014 and 2013, 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.

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. 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, 2015 and 2014.

Certain unvested awards under our 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, as further discussed in Note 11 of the Notes to Consolidated Financial Statements. There were 65,000 and 74,000 unvested participating shares outstanding as of June 30, 2015 and 2014, respectively.

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 unregulated 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, 2015, we had forward purchase contracts totaling $590,000 that expire in December, 2016, 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, 2015 or June 30, 2014. As of June 30, 2015 and June 30, 2014, the weighted average interest rate on our bank line of credit was 1.4% and 1.3%, respectively. During 2015 and 2014, we borrowed and repaid $126,000 and $691,000, respectively, from the bank line of credit, having a weighted average interest rate of 1.3% and 1.4%, respectively. A one percent (one hundred basis point) increase in our average interest rate would not have had a significant impact on our annual pre-tax net income.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULE

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 Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2015 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, 2015 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, 2015 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, 2015.

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, 2015, 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 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, 2015, 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, 2015 of the Company and our report dated August 25, 2015 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 25, 2015

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 can be found on our website by going to the following address: http://www.deltagas.com/corporate_governance.html. 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/corporate_governance.html.

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 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2015. 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 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2015. 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, 2015:

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)
—	—	745,430

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 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2015. 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 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2015. 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 2015 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2015. 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.
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.
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.
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 November 1, 1993 (Service Agreement Nos. 37,813, 37,814 and 37,815) and Appendix A to respective Service Agreements, effective November, 2010, by and between Columbia Gas Transmission Corporation and Registrant are incorporated herein by reference to Exhibit 10(h) to Registrants' Form 10-K (File No. 000-08788) for the period ended June 30, 2010.
10.10	FTS1 Service Agreements, dated October 4, 1994, (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 Corporation and Registrant are incorporated herein by reference to Exhibit 10(h) to Registrants' Form 10-K (File No. 000-08788) for the period ended June 30, 2010.
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	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.
10.27	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.
10.28	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.

10.29	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.
10.30	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.
10.31	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.
10.32	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.
10.33	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 Exhibits 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, 2012.
10.34	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.
10.35	Form of Notice of Performance Shares Award is incorporated herein by reference to Exhibit 10.35 to Registrant's Form 10-K (File No. 000-08788) for the period ended June 30, 2014.
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.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Database
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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, 2015, 2014 and 2013;

(iii) Consolidated Statements of Cash Flows for the years ended June 30, 2015, 2014 and 2013;

(iv) Consolidated Balance Sheets as of June 30, 2015 and 2014;

(v) Consolidated Statements of Changes in Shareholders' Equity for the years ended June 30, 2015, 2014 and 2013;

(vi) Notes to Consolidated Financial Statements;

(vii) Schedule II – Valuation and Qualifying Accounts for the years ended June 30, 2015, 2014 and 2013.

Pursuant to Rule 402 of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospects for purposes of Section 11 of the Securities Act of 1933 or Section 12 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

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 25th day of August, 2015.

DELTA NATURAL GAS COMPANY, INC.

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

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 25, 2015

(ii) Principal Financial Officer:

/s/John B. Brown (John B. Brown)	Chief Financial Officer, Treasurer and Secretary	August 25, 2015

(iii) Principal Accounting Officer:

/s/Matthew D. Wesolosky (Matthew D. Wesolosky)	Vice President - Controller	August 25, 2015

(iv) A Majority of the Board of Directors:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 25, 2015
/s/Jacob P. Cline, III (Jacob P. Cline, III)	Director	August 25, 2015
/s/Sandra C. Gray (Sandra C. Gray)	Director	August 25, 2015
/s/Edward J. Holmes (Edward J. Holmes)	Director	August 25, 2015
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 25, 2015
/s/Fred N. Parker (Fred N. Parker)	Director	August 25, 2015
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 25, 2015
/s/Michael R. Whitley (Michael R. Whitley)	Director	August 25, 2015

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, 2015 and 2014, 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, 2015. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Delta Natural Gas Company, Inc. and subsidiaries as of June 30, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2015, 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, present fairly, in all material respects, the information set forth therein.

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, 2015, 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 August 25, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 25, 2015

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Year Ended June 30,	2015	2014	2013
Operating Revenues			
Regulated revenues	$ 52,681,120	$ 57,054,180	$ 46,427,203
Non-regulated revenues	33,507,118	38,791,691	34,237,634
Total operating revenues	$ 86,188,238	$ 95,845,871	$ 80,664,837
Operating Expenses			
Regulated purchased natural gas	$ 22,728,766	$ 27,215,425	$ 17,825,487
Non-regulated purchased natural gas	26,713,424	29,059,426	26,011,164
Operation and maintenance	14,608,835	15,495,537	15,208,162
Depreciation and amortization	6,377,743	6,147,618	6,092,651
Taxes other than income taxes	2,795,609	2,324,426	2,338,694
Total operating expenses	$ 73,224,377	$ 80,242,432	$ 67,476,158
Operating Income	$ 12,963,861	$ 15,603,439	$ 13,188,679
Other Income and Deductions, Net	$ 25,097	$ 201,462	$ 150,816
Interest Charges			
Interest on long-term debt	$ 2,309,124	$ 2,373,024	$ 2,438,325
Other interest (income) expense	51,538	51,563	(822,190)
Amortization of debt expense	240,000	246,600	253,800
Total interest charges	$ 2,600,662	$ 2,671,187	$ 1,869,935
Net Income Before Income Taxes	$ 10,388,296	$ 13,133,714	$ 11,469,560
Income Tax Expense	3,892,215	4,858,586	4,268,784
Net Income	$ 6,496,081	$ 8,275,128	$ 7,200,776
Earnings Per Common Share (Note 11)			
Basic and Diluted	$ .92	$ 1.19	$ 1.05
Dividends Declared Per Common Share	$ .80	$ .76	$ .72

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,	2015	2014	2013
Cash Flows From Operating Activities			
Net income	$ 6,496,081	$ 8,275,128	$ 7,200,776
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	6,617,743	6,420,525	6,428,051
Deferred income taxes and investment tax credits	1,449,471	(515,492)	1,959,741
Change in cash surrender value of officer's life insurance	(19,036)	(67,722)	(27,300)
Share-based compensation	1,095,051	1,111,966	921,709
Excess tax deficiency from share-based compensation	(9,574)	(8,967)	(8,946)
(Increase) decrease in assets			
Accounts receivable	871,270	2,216,925	(841,574)
Natural gas in storage	2,491,337	(1,644,186)	1,451,494
Deferred natural gas cost	724,923	3,197,921	(536,552)
Materials and supplies	(12,578)	(288,597)	9,256
Prepayments	(363,263)	(1,253,798)	893,490
Other assets	225,771	11,556	(177,919)
Increase (decrease) in liabilities			
Accounts payable	(1,135,821)	169,226	2,725,470
Accrued taxes	(80,925)	83,528	(2,757,561)
Asset retirement obligations	375,073	(553,612)	(493,946)
Other liabilities	20,658	185,805	(3,189,770)
Net cash provided by operating activities	$ 18,746,181	$ 17,340,206	$ 13,556,419
Cash Flows From Investing Activities			
Capital expenditures	$ (9,010,876)	$ (8,077,642)	$ (7,179,473)
Proceeds from sale of property, plant and equipment	161,311	268,082	131,545
Other	(60,000)	(60,000)	(60,000)
Net cash used in investing activities	$ (8,909,565)	$ (7,869,560)	$ (7,107,928)

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,	2015	2014	2013
Cash Flows From Financing Activities			
Dividends on common shares	$ (5,639,791)	$ (5,289,911)	$ (4,951,002)
Issuance of common shares	532,712	595,249	587,359
Excess tax benefit from share-based compensation	18,823	39,472	35,112
Repayment of long-term debt	(1,500,000)	(1,500,000)	(1,500,000)
Borrowings on bank line of credit	126,430	691,157	—
Repayment of bank line of credit	(126,430)	(691,157)	—
Net cash used in financing activities	$ (6,588,256)	$ (6,155,190)	$ (5,828,531)
Net Increase in Cash and Cash Equivalents	$ 3,248,360	$ 3,315,456	$ 619,960
Cash and Cash Equivalents, Beginning of Year	13,675,918	10,360,462	9,740,502
Cash and Cash Equivalents, End of Year	$ 16,924,278	$ 13,675,918	$ 10,360,462
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	$ 2,369,078	$ 2,436,435	$ 2,509,962
Income taxes (net of refunds)	$ 3,312,944	$ 5,819,956	$ 1,573,321
Significant non-cash transactions			
Accrued capital expenditures	$ 207,169	$ 328,638	$ 301,679

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,	2015	2014
Assets		
Current Assets		
Cash and cash equivalents	$ 16,924,278	$ 13,675,918
Accounts receivable, less accumulated allowances for doubtful accounts of $258,000 and $360,000 in 2015 and 2014, respectively	5,760,550	6,681,964
Natural gas in storage, at average cost (Note 1)	4,634,162	7,125,499
Deferred natural gas costs (Notes 1 and 14)	—	724,923
Materials and supplies, at average cost	543,563	574,699
Prepayments	3,347,187	3,491,257
Total current assets	$ 31,209,740	$ 32,274,260
Property, Plant and Equipment	$ 236,780,490	$ 229,367,319
Less - Accumulated provision for depreciation	(98,741,351)	(93,551,799)
Net property, plant and equipment	$ 138,039,139	$ 135,815,520
Other Assets		
Cash surrender value of life insurance (face amount of $951,000 and $948,000 in 2015 and 2014, respectively)	$ 421,183	$ 402,147
Prepaid pension (Note 6)	2,145,969	3,291,974
Regulatory assets (Note 1)	14,917,823	13,198,199
Unamortized debt expense (Notes 1 and 10)	83,704	90,304
Other non-current assets	977,312	952,757
Total other assets	$ 18,545,991	$ 17,935,381
Total assets	$ 187,794,870	$ 186,025,161

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,	2015	2014
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 5,426,395	$ 6,706,021
Current portion of long-term debt (Note 10)	1,500,000	1,500,000
Accrued taxes	1,472,401	1,553,670
Customers' deposits	600,788	593,010
Accrued interest on debt	112,296	120,712
Accrued vacation	749,031	752,905
Deferred income taxes	140,929	39,718
Regulatory liability - refundable natural gas costs (Note 1)	756	—
Other liabilities	610,238	591,606
Total current liabilities	$ 10,612,834	$ 11,857,642
Long-Term Debt (Note 10)	$ 52,000,000	$ 53,500,000
Long-Term Liabilities		
Deferred income taxes	$ 41,989,138	$ 40,537,879
Investment tax credits	10,800	24,600
Regulatory liabilities (Note 1)	1,137,758	1,165,260
Asset retirement obligations (Note 4)	3,795,590	3,260,721
Other long-term liabilities	1,027,096	950,707
Total long-term liabilities	$ 47,960,382	$ 45,939,167
Commitments and Contingencies (Note 13)		
Total liabilities	$ 110,573,216	$ 111,296,809
Shareholders' Equity		
Common shares ($1.00 par value), 20,000,000 shares authorized; 7,026,500 and 6,942,758 shares outstanding at June 30, 2015 and June 30, 2014, respectively	$ 7,026,500	$ 6,942,758
Premium on common shares	48,735,608	47,182,338
Retained earnings	21,459,546	20,603,256
Total shareholders' equity	$ 77,221,654	$ 74,728,352
Total liabilities and shareholders' equity	$ 187,794,870	$ 186,025,161

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, 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

	Year Ended June 30, 2014			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415
Net income	—	—	8,275,128	8,275,128
Issuance of common shares	28,809	566,440	—	595,249
Issuance of common shares under the incentive compensation plan	49,696	299,930	—	349,626
Share-based compensation expense	—	762,340	—	762,340
Tax benefit from share-based compensation	—	30,505	—	30,505
Dividends on common shares	—	—	(5,289,911)	(5,289,911)
Balance, end of year	$ 6,942,758	$ 47,182,338	$ 20,603,256	$ 74,728,352

	Year Ended June 30, 2013			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,803,941	$ 44,048,201	$ 15,368,265	$ 66,220,407
Net income	—	—	7,200,776	7,200,776
Issuance of common shares	28,436	558,923	—	587,359
Issuance of common shares under the incentive compensation plan	31,876	232,226	—	264,102
Share-based compensation expense	—	657,607	—	657,607
Tax benefit from share-based compensation	—	26,166	—	26,166
Dividends on common shares	—	—	(4,951,002)	(4,951,002)
Balance, end of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415

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 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.

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)	2015	2014
Regulated segment		
Distribution, transmission and storage	210,659	203,969
General, miscellaneous and intangibles	22,785	22,421
Construction work in progress	739	381
Total regulated segment	234,183	226,771
Non-regulated segment	2,597	2,596
Total property, plant and equipment	236,780	229,367

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 2.8%, 2.8% and 2.9% of average depreciable plant for 2015, 2014 and 2013, respectively.

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 Sheet. 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 2015, 2014 or 2013.

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 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, as 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 and include the following:

(000)	2015	2014
Unbilled revenues ($)	1,674	1,788
Unbilled gas costs ($)	462	622
Unbilled volumes (Mcf)	69	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 transportation 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 revenue from Delta Resources is at tariff rates and eliminated 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 revenue from Delgasco is at tariff rates and eliminated 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 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 transportation expenses paid by Delta Resources to Delta are at tariff rates and are eliminated 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 transportation expenses paid by Delgasco to Delta are at tariff rates and are eliminated 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 are eliminated 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 both the hydrocarbon content of the liquids and the market price for natural gas liquids.

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

($000)	2015	2014
Regulatory assets		
Current assets		
Deferred natural gas costs	—	725
Other assets		
Conservation/efficiency program expenses	173	164
Loss on extinguishment of debt	2,916	3,149
Asset retirement obligations	4,668	4,377
Accrued pension	7,161	5,508
Total other assets	14,918	13,198
Total regulatory assets	14,918	13,923
Regulatory liabilities		
Current liabilities		
Refundable natural gas costs	1	—
Long-term liabilities		
Accrued cost of removal on long-lived assets	417	355
Regulatory liability for deferred income taxes	721	810
Total long-term liabilities	1,138	1,165
Total regulatory liabilities	1,139	1,165

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 32 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 fully 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) New Accounting Pronouncements

In September, 2013, the Internal Revenue Service ("IRS") issued final regulations regarding the tax treatment of amounts paid to acquire, produce or improve tangible property, which update temporary regulations issued by the IRS in December, 2011. In 2014, the IRS stated its intent to issue further guidance for specific industry sectors, including natural gas. The final regulations are effective for our tax year beginning July 1, 2014; however, we do not expect compliance with the final regulations and industry specific guidance to have a material impact on our results of operations, financial position or cash flows.

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. The guidance is effective for our quarterly report ending September 30, 2018 and we are evaluating the methods of adoption allowed by the new standard and the effect the standard is expected to have on our results of operations, financial position or cash flows.

In June, 2014, the Financial Accounting Standards Board issued guidance on share-based payments where performance targets can be achieved subsequent to the requisite service period. The guidance, effective for our quarter ending September 30, 2016, is not expected to have a material impact on our results of operations, financial position or cash flows.

In April, 2015, the Financial Accounting Standards Board issued guidance on the presentation of debt issuance costs which requires the debt issuance cost to be recognized as a direct deduction from the carrying amount of the debt liability. The guidance, effective for our quarter ending September, 2016, is not expected to have a material impact on our results of operations, financial position or cash flows.

In May, 2015, the Financial Accounting Standards Board issued guidance simplifying the disclosure of certain investments measured using the net asset value per share of the investment. The guidance no longer requires such investments to be categorized within the fair value hierarchy. The guidance, effective for quarter ending September, 2016, is not expected to have a material impact on our results of operations, financial position or cash flows.

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 and net realizable value. The guideline, effective for our quarter ending September, 2017, is not expected to have a material impact on our results of operations, financial position or cash flows.

(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 are recorded at fair value and 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 fair value of the trust assets are as follows:

($000)	2015	2014
Money market	27	44
U.S. equity securities	395	379
Foreign equity funds	185	167
U.S. fixed income funds	177	121
Foreign fixed income funds	57	53
Absolute return strategy mutual funds	136	143
Total trust assets	977	907

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, as well as current portion of long-term debt on the Consolidated Balance Sheets, are stated at historical cost. 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.

	2015		2014	
($000)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
4.26% Series A Notes	53,500	52,935	55,000	55,576

(4) Asset Retirement Obligations

Legal obligations

As of June 30, 2015 and 2014, 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 as asset retirement obligations on the accompanying Consolidated Balance Sheets:

($000)	2015	2014
Balance, beginning of year	3,261	3,547
Liabilities incurred	21	138
Liabilities settled	(232)	(567)
Accretion	246	258
Revisions in estimated cash flows	500	(115)
Balance, end of year	3,796	3,261

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, $417,000 and $355,000 of such accrued cost of removal was recorded as a regulatory liability on the accompanying Consolidated Balance Sheets as of June 30, 2015 and 2014, 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 current portion of the net accumulated deferred income tax liability is shown as current liabilities and the long-term portion is included in long-term liabilities 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)	2015	2014
Deferred Tax Liabilities		
Current		
Deferred natural gas cost	—	(275)
Prepaid expenses	(452)	(359)
	(452)	(634)
Non-Current		
Accelerated depreciation	(38,108)	(36,903)
Pension	(805)	(1,240)
Regulatory assets - asset retirement obligations	(876)	(820)
Regulatory assets - loss on extinguishment of debt	(1,107)	(1,196)
Regulatory assets - unrecognized accrued pension	(2,718)	(2,091)
Regulatory liabilities	(1,268)	(1,268)
Other	(1,119)	(954)
	(46,001)	(44,472)
Total deferred tax liabilities	(46,453)	(45,106)
Deferred Tax Assets		
Current		
Accrued employee benefits	126	405
Bad debt reserve	98	99
Other	86	90
	310	594
Non-Current		
Accrued employee benefits	1,005	992
Asset retirement obligations	1,378	1,176
Investment tax credits	7	15
Regulatory liabilities	1,540	1,570
Section 263(a) capitalized costs	64	105
Other	19	76
	4,013	3,934
Total deferred tax assets	4,323	4,528
Net accumulated deferred income tax liability	(42,130)	(40,578)

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

($000)	2015	2014	2013
Current			
Federal	1,950	4,532	1,940
State	493	842	390
Total	2,443	5,374	2,330
Deferred	1,449	(515)	1,939
Income tax expense	3,892	4,859	4,269

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

(%)	2015	2014	2013
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)	(0.2)
Other differences, net	(0.4)	(0.9)	(0.6)
Effective income tax rate	37.5	37.0	37.2

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, 2015 and 2014, we did not have any unrecognized tax positions, which, if recognized, would impact the effective tax rate. As of June 30, 2015 and 2014, we had $5,000 of interest accrued on unrecognized tax positions. In 2014 we recognized interest income of $4,000 on unrecognized tax positions in the Consolidated Statements of Income.

The following is a reconciliation of our unrecognized tax benefits:

($000)	2015	2014
Balance, beginning of year	64	101
Gross decreases - tax positions in prior period	(59)	(37)
Balance, end of year	5	64

We file income tax returns in federal and Kentucky jurisdictions. Tax years previous to June 30, 2013 and June 30, 2012 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 plans to recognize the funded status of a defined benefit pension 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 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, 2015 and June 30, 2014, respectively, are as follows:

($000)	2015	2014
Change in Benefit Obligation		
Benefit obligation at beginning of year	26,383	23,521
Service cost	990	1,023
Interest cost	1,056	1,038
Actuarial loss	1,219	1,810
Benefits paid	(810)	(1,009)
Benefit obligation at end of year	28,838	26,383
Change in Plan Assets		
Fair value of plan assets at beginning of year	29,675	26,201
Actual return on plan assets	1,119	3,983
Employer contributions	1,000	500
Benefits paid	(810)	(1,009)
Fair value of plan assets at end of year	30,984	29,675
Recognized Amounts		
Projected benefit obligation	(28,838)	(26,383)
Plan assets at fair value	30,984	29,675
Funded status	2,146	3,292
Net amount recognized as prepaid pension on the Consolidated Balance Sheets	2,146	3,292
Items Not Yet Recognized as a Component of Net Periodic Benefit Cost		
Prior service cost	(230)	(316)
Accumulated net losses	7,391	5,824
Amounts recognized as regulatory assets	7,161	5,508

The accumulated benefit obligation was $25,012,000 and $22,810,000 for 2015 and 2014, respectively.

($000)	2015	2014	2013
Components of Net Periodic Benefit Cost			
Service cost	990	1,023	1,116
Interest cost	1,056	1,038	913
Expected return on plan assets	(1,711)	(1,567)	(1,578)
Amortization of unrecognized net loss	244	342	615
Amortization of prior service cost	(86)	(86)	(86)
Net periodic benefit cost	493	750	980
Weighted-Average % Assumptions Used to Determine Benefit Obligations			
Discount rate	4.25	4.25	4.5
Rate of compensation increase	4.0	4.0	4.0
Weighted-Average % Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	4.25	4.5	4.0
Expected long-term return on plan assets	6.0	6.0	7.0
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 70% equity investments and 30% 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. 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	2015	2014
Asset Class			
Cash and cash equivalents	3	3	3
Equity Securities			
U.S. equity securities	41	47	48
Foreign equity securities	20	12	19
	61	59	67
Fixed Income Securities			
U. S. fixed income security	15	18	12
Foreign fixed income security	8	6	6
	23	24	18
Other Securities			
Absolute return strategy mutual funds	13	14	12
	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 plan assets:

($000)	2015	Level 1	Level 2	Level 3
Asset Class				
Cash	1,072	1,072	—	—
Equity Securities				
U.S. equity securities	14,602	14,602	—	—
Foreign equity securities	3,690	3,690	—	—
	18,292	18,292	—	—
Fixed Income Securities				
U.S. treasury securities	524	524	—	—
High yield funds	3,284	3,284	—	—
Foreign bond funds	1,857	1,857	—	—
U.S. corporate bonds	902	—	902	—
Other	734	—	734	—
	7,301	5,665	1,636	—
Other Securities				
Absolute return strategy mutual funds	4,319	4,319	—	—
Total	30,984	29,348	1,636	—

($000)	2014	Level 1	Level 2	Level 3
Asset Class				
Cash	1,026	1,026	—	—
Exchange Traded Mutual Funds				
U.S. equity securities	13,828	13,828	—	—
Foreign equity securities	5,706	5,706	—	—
	19,534	19,534	—	—
Fixed Income Securities				
U.S. treasury securities	593	593	—	—
High yield funds	1,773	1,773	—	—
Foreign bond funds	1,771	1,771	—	—
U.S. corporate bonds	714	—	714	—
Other	577	—	577	—
	5,428	4,137	1,291	—
Other Securities				
Absolute return strategy mutual funds	3,687	3,687	—	—
Total	29,675	28,384	1,291	—

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 a $1,000,000 discretionary contribution to the defined benefit plan in fiscal 2015. We expect to contribute $500,000 to the defined benefit plan in fiscal 2016.

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

($000)

2016	3,256
2017	792
2018	1,383
2019	1,578
2020	1,135
2021 - 2025	8,024

Effective May 9, 2008, any employees hired on and after that date were not eligible to participate in our defined benefit plan. Freezing the defined benefit 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 plan described below.

Employee Savings Plan

We have an Employee Savings Plan ("Savings Plan") under which eligible employees may elect to contribute a portion of their annual compensation up to the maximum amount permitted by law. The Company matches 100% of the employee's contribution up to a maximum company contribution of 4% of the employee's annual compensation. 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 Savings Plan account. Company contributions are discretionary and subject to change with approval from our Board of Directors. For 2015, 2014 and 2013, our Savings Plan expense was $359,000, $350,000 and $313,000, 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 2015, 2014 and 2013 Delta contributed $60,000 each year to the trust. As of June 30, 2015 and 2014, the irrevocable trust assets are $977,000 and $907,000, 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 26,412, 28,809 and 28,436 shares in 2015, 2014 and 2013, respectively. We registered 400,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2015 there were approximately 67,000 shares available for issuance.

(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, 2015 and June 30, 2014. The maximum amount borrowed during 2015 and 2014 was $126,000 and $691,000, respectively. The bank line of credit extends through June 30, 2017. The interest rate on the used line of credit was the London Interbank Offered Rate plus 1.15% and, effective July 1, 2015, 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)	
2016	1,500
2017	1,500
2018	1,500
2019	1,500
Thereafter	47,500
Total long-term debt	53,500

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. At June 30, 2015 and 2014, the unamortized balance was $3,000,000 and $3,240,000, respectively. As of June 30, 2015 and 2014, the unamortized balance included loss on extinguishment of debt of $2,916,000 and $3,149,000, 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:

	2015	2014	2013
Numerator - Basic and Diluted ($000)			
Net income	6,496	8,275	7,201
Dividends paid	(5,640)	(5,290)	(4,951)
Undistributed earnings	856	2,985	2,250
Allocated to common shares:			
Percentage allocated to common shares (a)	99.4%	99.4%	99.4%
Undistributed earnings	851	2,966	2,238
Dividends paid	5,609	5,263	4,930
Net income available to common shares	6,460	8,229	7,168
Denominator - Basic and Diluted			
Weighted average common shares (b)	7,002,694	6,918,725	6,843,455
Earnings per Common Share - Basic and Diluted ($)	0.92	1.19	1.05

(a) Percentage allocated to weighted average common shares outstanding:

Common shares outstanding	7,002,694	6,918,725	6,843,455
Unvested participating shares outstanding (c)	45,500	44,750	38,417
Total	7,048,194	6,963,475	6,881,872
Percentage allocated to common shares	99.4%	99.4%	99.4%

(b) 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, 2015, 2014 and 2013.

(c) 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. There were no antidilutive shares in 2015, 2014 and 2013. There were 65,000, 74,000 and 68,000 unvested participating shares outstanding as of June 30, 2015, 2014 and 2013, 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 $69,000, $68,000 and $71,000 for the years ended June 30, 2015, 2014 and 2013, 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 or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $4.3 million would be paid in addition to continuation of specified benefits for up to five years. Additionally, upon a change in control, all unvested shares awarded under our Incentive Compensation Plan, as further discussed in Note 16 of the Notes to Consolidated Financial Statements, would immediately vest.

We are not a party to any material pending legal proceedings.

We have entered into a forward purchase agreements for a portion of our non-regulated segment's natural gas purchases beginning in July, 2015 and expiring in December, 2016. 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 customers' natural gas requirements. The agreements have an aggregate minimum purchase obligations of $440,000 and $150,000 for our fiscal years ending June 30, 2016 and June 30, 2017, 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 rates and tariffs. Their regulation of our business includes setting the rates we are permitted to charge our regulated customers. We monitor our need to file requests with them for a general rate increase for our natural gas distribution and transportation services. They have 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. 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 margins on lost sales due to the program and providing incentives for us to promote customer conservation. Our rates are adjusted annually to recover the costs incurred under these programs, the reimbursement of margins on lost sales and the incentives provided to us.

In addition to regulation by the Kentucky Public Service Commission, we may obtain non-exclusive franchises from the cities in which we operate authorizing us to place our facilities in the streets and public grounds. No utility may obtain a franchise until it has obtained approval from the Kentucky Public Service Commission to bid on such franchise. We hold franchises in five of the cities we serve, and we continue to operate under the conditions of expired franchises in five 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.

(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 2015. Our largest customer provided approximately $17,852,000 and $12,569,000 of non-regulated revenues during 2015 and 2014, respectively. Our second largest customer provided approximately $7,127,000, $9,494,000 and $17,866,000 of non-regulated revenues during 2015, 2014 and 2013, respectively. There is no assurance that revenues from these customers will continue at these levels.

Our regulated segment purchased approximately 99% and 98% of its natural gas from Atmos Energy Marketing and Midwest Energy Services in 2015 and 2014, respectively. In 2013, we purchased approximately 98% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services.

Our non-regulated segment purchased approximately 99% of its natural gas from Atmos Energy Marketing and Midwest Energy Services in 2015. In 2014, we purchased approximately 96% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services. In 2013, we purchased approximately 92% of our natural gas from Atmos Energy Marketing and M&B Services.

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)	2015	2014	2013
Operating Revenues			
Regulated			
External customers	52,681	57,054	46,427
Intersegment	3,869	4,041	4,145
Total Regulated	56,550	61,095	50,572
Non-regulated			
External customers	33,507	38,792	34,238
Eliminations for intersegment	(3,869)	(4,041)	(4,145)
Total operating revenues	86,188	95,846	80,665
Operating Expenses			
Regulated			
Purchased natural gas	22,729	27,215	17,825
Depreciation and amortization	6,293	6,068	6,023
Other	15,819	15,285	14,701
Total regulated	44,841	48,568	38,549
Non-regulated			
Purchased natural gas	26,713	29,059	26,011
Depreciation and amortization	84	80	70
Other	5,455	6,576	6,990
Total non-regulated	32,252	35,715	33,071
Eliminations for intersegment	(3,869)	(4,041)	(4,145)
Total operating expenses	73,224	80,242	67,475
Other Income and Deductions, Net			
Regulated	25	183	151
Non-regulated	—	18	—
Total other income and deductions, net	25	201	151
Interest Charges			
Regulated	2,551	2,633	2,688
Non-regulated	50	38	(818)
Total interest charges	2,601	2,671	1,870
Income Tax Expense			
Regulated	3,553	3,907	3,676
Non-regulated	339	952	593
Total income tax expense	3,892	4,859	4,269
Net Income			
Regulated	5,748	6,407	5,970
Non-regulated	748	1,868	1,231
Total net income	6,496	8,275	7,201
Assets			
Regulated	183,566	181,530	177,662
Non-regulated	4,229	4,495	6,268
Total assets	187,795	186,025	183,930
Capital Expenditures			
Regulated	8,991	8,078	6,983
Non-regulated	20	—	196
Total capital expenditures	9,011	8,078	7,179

(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, 2015, approximately 745,000 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.

Compensation expense for share-based compensation is recorded in the non-regulated segment and included 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. Our share-based compensation expense was $1,095,000, $1,112,000 and $922,000 for 2015, 2014 and 2013, respectively.

Excess tax benefits of $9,000 and $31,000 were recognized as an increase to premium on common shares on our 2015 and 2014 Consolidated Balance Sheets, respectively, which decreased our taxes payable as the deduction for income tax purposes exceeds the compensation expense recognized for financial reporting purposes. The excess tax benefits can be utilized to offset tax deficiencies related to share-based compensation in subsequent periods.

Stock Awards

In 2015, 2014 and 2013, common stock was awarded to virtually all Delta employees and directors having grant date fair values of $443,000 (22,000 shares), $350,000 (17,000 shares) and $264,000 (12,000 shares), respectively. 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 2015, 2014 and 2013, performance shares were awarded to the Company's executive officers having grant date fair values of $773,000 (39,000 shares), $801,000 (39,000 shares) and $844,000 (39,000 shares), respectively. The performance share awards 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. 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.

As of June 30, 2015 the performance objectives for the performance shares awarded in 2015 have been satisfied and subject to further limitations of the plan, up to 26,000 unvested shares will be issued to the recipients, subject to a service condition whereby the award shall vest in one-third increments each year beginning August 31, 2015 and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. Unvested shares of executive officers who retire after having met the "normal retirement age" as defined under the defined benefit retirement plan sponsored by the Company and having attained the age of sixty-seven at the time of termination of employment will fully vest upon their retirement date. The performance objectives for the performance shares awarded in 2014 were met and 39,000 unvested shares were issued on August 31, 2014, of which 26,000 shares remain unvested as of June 30, 2015.

For 2015, 2014 and 2013, compensation expense related to the performance shares was $652,000, $762,000 and $658,000, respectively. Compensation expense of $332,000 is expected to be recognized between 2016 and 2018 for the unvested shares.

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, 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, 2015 is 1.4 years.

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, 2014	74,000	20.28
Granted (a)	39,000	19.82
Vested	(35,000)	(19.60)
Forfeited	(13,000)	(19.82)
Unvested shares at June 30, 2015	65,000	20.47

(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.

Quarter Ended	Operating Revenues	Operating Income	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2015				
September 30	$ 13,321,305	$ 160,061	$ (311,125)	$ (0.05)
December 31	25,875,266	4,899,101	2,656,534	0.38
March 31	35,085,307	7,286,400	4,155,136	0.59
June 30	11,906,360	618,299	(4,464)	—
Fiscal 2014				
September 30	$ 13,041,272	$ 692,098	$ 79,409	$ 0.01
December 31	25,810,664	5,624,971	3,134,729	0.45
March 31	40,435,516	8,886,123	5,173,624	0.74
June 30	16,558,419	400,247	(112,634)	(0.01)

(18) Subsequent Events

In August, 2015 8,400 shares of common stock were awarded to all directors having a grant date fair value of $169,000. In August, 2015, performance shares were awarded to the Company's executive officers. The performance share awards vest only if the performance objective of the awards is met, which is based on the Company's fiscal 2016 audited earnings per share, before any cash bonuses or share-based compensation. Subject to further limitations described in the Plan, all performance shares paid shall be in the form of unvested shares, which contain a service condition whereby recipients of the awards shall vest in one-third increments each year beginning on August 31, 2016, and annually each August 31 thereafter until fully vested as long as the recipient is an employee throughout each such service period. Unvested shares of executive officers who retire after having met the "normal retirement age" as defined under the defined benefit retirement plan sponsored by the Company and having attained the age of sixty-seven at the time of termination of employment will fully vest upon their retirement date. The maximum number of shares which could be issued under the performance awards is 39,000, having a grant date fair value of $787,000.

SCHEDULE II

DELTA NATURAL GAS COMPANY, INC.

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED JUNE 30, 2015, 2014 and 2013

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, 2015	$ 360,000	$ 170,631	$ 237,267	$ 509,498	$ 258,400
June 30, 2014	536,255	107,131	225,502	508,888	360,000
June 30, 2013	157,000	496,512	140,178	257,435	536,255

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

	2015	2014	2013	2012	2011
Earnings					
Net income	$ 6,496,081	$ 8,275,128	$ 7,200,776	$ 5,783,998	$ 6,364,895
Provisions for income taxes (a)	3,892,215	4,858,586	4,268,784	3,258,144	3,759,607
Fixed charges	2,623,662	2,694,187	2,770,935	4,321,256	4,112,798
Total	$ 13,011,958	$ 15,827,901	$ 14,240,495	$ 13,363,398	$ 14,237,300
Fixed Charges					
Interest on debt (a)	$ 2,360,662	$ 2,424,587	$ 2,493,135	$ 3,969,025	$ 3,701,535
Amortization of debt expense	240,000	246,600	253,800	329,231	387,263
One third of rental expense	23,000	23,000	24,000	23,000	24,000
Total	$ 2,623,662	$ 2,694,187	$ 2,770,935	$ 4,321,256	$ 4,112,798
Ratio of earnings to fixed charges	4.96x	5.87x	5.14x	3.09x	3.46x

(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.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in this Post-Effective Amendment No. 1 to Registration Statement No. 333-130301 on Form S-3 of our reports dated August 25, 2015, relating to the consolidated financial statements and the 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 the Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2015.

/s/ DELOITTE & TOUCHE LLP

Indianapolis, Indiana
August 25, 2015

EXHIBIT 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

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

I, Glenn R. Jennings, certify that:

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

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

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

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

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

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

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

DATE: August 25, 2015

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

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

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

I, John B. Brown, certify that:

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

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

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

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

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

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

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

DATE: August 25, 2015

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

Exhibit 32.1

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

In connection with the Annual Report of Delta Natural Gas Company, Inc. on Form 10-K for the period ending June 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: August 25, 2015

/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, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Brown, Chief Financial Officer, Treasurer and Secretary of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: August 25, 2015

/s/John B. Brown

John B. Brown
Chief Financial Officer, Treasurer and Secretary

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Exhibit 13-4

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, 2016

☐ **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 ☐

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. $148,491,236.

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 26, 2016, Delta Natural Gas Company, Inc. had outstanding 7,092,263 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, 2016, 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, “2016”, “2015” and “2014” 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.

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 2016, 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 and/or 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, 2016, 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 Atmos Energy Marketing ("Atmos") for our Columbia Gas, Columbia Gulf, Tennessee and Texas Eastern supplied areas. Under these commodity requirements agreements, Atmos is obligated to supply the volumes consumed by our regulated customers in defined sections of our service areas. We are not obligated to purchase any minimum quantities from Atmos or 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 Atmos 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, 2016, approximately 53% of our regulated natural gas supply was purchased under our agreements with Atmos.

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, 2016, approximately 46% 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 2016, Tennessee transported for us a total of 1,640,000 Mcf, or approximately 43% 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 Atmos, 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 2016, Columbia Gas and Columbia Gulf transported for us a total of 329,000 Mcf, or approximately 9% 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 agreement with Columbia Gulf extends 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 2016 constituted approximately 46% 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, Atmos has an arrangement with Texas Eastern to transport the natural gas to us that we purchase from Atmos to supply our customers' requirements in specific geographic areas. In our fiscal year ended June 30, 2016, Texas Eastern transported approximately 17,000 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 34,000 Mcf from Vinland during fiscal 2016. 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 2016, the natural gas we purchased from Vinland constituted less than 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 rates and tariffs. The Kentucky Public Service Commission's regulation of our business includes approving the rates we are permitted to charge our regulated customers. 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. 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 positions 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.

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, 2016, approximately 99% 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 2016. Atmos provided approximately $5,656,000, $7,127,000 and $5,206,000 of non-regulated revenues during 2016, 2015 and 2014, respectively. Greystone, LLC provided approximately $11,555,000, $17,852,000 and $12,569,000 of non-regulated revenues during 2016, 2015 and 2014. 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 108,000 Mcf of natural gas during 2016 which was approximately 1% 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, 2016, approximately 1% 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, 2016, 94% of our non-regulated natural gas supply was purchased under our agreement with Midwest.

Additionally, our non-regulated segment purchases natural gas from Atmos as needed. This spot purchasing arrangement is pursuant to an agreement with Atmos containing an evergreen clause which permits either party to terminate the agreement by providing not less than sixty days written notice. Our purchases from Atmos under this spot purchase agreement are generally month-to-month. However, we have the option of forward-pricing 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, 2016, approximately 5% of our non-regulated natural gas supply was purchased under our agreement with Atmos.

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.

Capital Expenditures

Capital expenditures during 2016 were $6.3 million and for 2017 are estimated to be $8.5 million. Our expenditures include system extensions as well as 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, 2016.

Our current bank line of credit extends through June 30, 2017 and will be available to meet capital expenditure and operating cash requirements. The amounts and types of future long-term debt and equity financings will depend upon our capital needs and market conditions.

We currently have long-term debt of $52,000,000 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, 2016, 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,	2016	2015	2014	2013	2012
Average Regulated Customers Served	34,415	34,384	34,490	34,701	34,860
Operating Revenues ($000) (a)					
Regulated revenues					
Natural gas sales	35,319	46,828	51,542	41,202	37,660
Natural gas transportation	9,225	9,366	9,163	9,037	8,375
Other	289	356	390	333	324
Total regulated revenues	44,833	56,550	61,095	50,572	46,359
Non-regulated revenues	22,888	33,507	38,792	34,238	31,423
Intersegment eliminations (b)	(3,591)	(3,869)	(4,041)	(4,145)	(3,704)
Total	64,130	86,188	95,846	80,665	74,078
System Throughput (Million Cu. Ft.) (a)					
Regulated					
Natural gas sales	2,623	3,261	3,351	3,057	2,448
Natural gas transportation	17,413	16,855	16,423	16,783	15,949
Total regulated throughput	20,036	20,116	19,774	19,840	18,397
Non-regulated	7,436	7,357	7,241	7,650	6,455
Intersegment eliminations (b)	(7,288)	(7,210)	(7,096)	(7,497)	(6,326)
Total	20,184	20,263	19,919	19,993	18,526
Average Annual Consumption Per Average Residential Customer (Thousand Cu. Ft.)	47	59	61	56	44
Lexington, Kentucky Degree Days					
Actual	3,765	4,964	4,855	4,667	3,977
Percent of 30 year average	83	110	107	104	83

(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 and/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 and determines 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 differs from 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.

DERIVATIVES LEGISLATION COULD ADVERSELY AFFECT OUR ABILITY TO HEDGE RISKS ASSOCIATED WITH OUR BUSINESS OR OTHERWISE HAVE A MATERIAL AND ADVERSE EFFECT ON OUR FINANCIAL POSITION, RESULTS OF OPERATIONS OR CASH FLOWS.

As part of our risk management strategy, we currently use, and historically have used, forward commodity contracts, which meet the criteria of a derivative. The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) adopted a comprehensive framework for the regulation of over-the-counter swaps (“OTC swaps”). The Dodd-Frank Act divides regulatory authority over swap agreements between the SEC and the Commodity Futures Trading Commission (“CFTC”) and requires that most OTC swaps be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. While the SEC and CFTC have adopted numerous regulations relating to OTC swaps, they are still in the process of rulemaking to address all of the requirements regarding OTC swaps under the Dodd-Frank Act. Current and future legal and regulatory requirements, restrictions and regulations imposed under the Dodd-Frank Act could increase the operational and transactional cost of derivatives contracts and could affect the number and/or creditworthiness of available counterparties. Our inability to enter into derivative contracts at favorable terms, or at all, could increase our operating expenses and our ability to hedge our business risks.

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 DEPENDENT ON 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, 2016 our Series A Notes permit us to pay up to an additional $23,341,000 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 and/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.

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 2.1 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 108,000 Mcf of natural gas during fiscal 2016 from all the properties described in this paragraph.

Our assets have no significant encumbrances.

Item 3. Legal Proceedings

We are not currently a party to any 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.

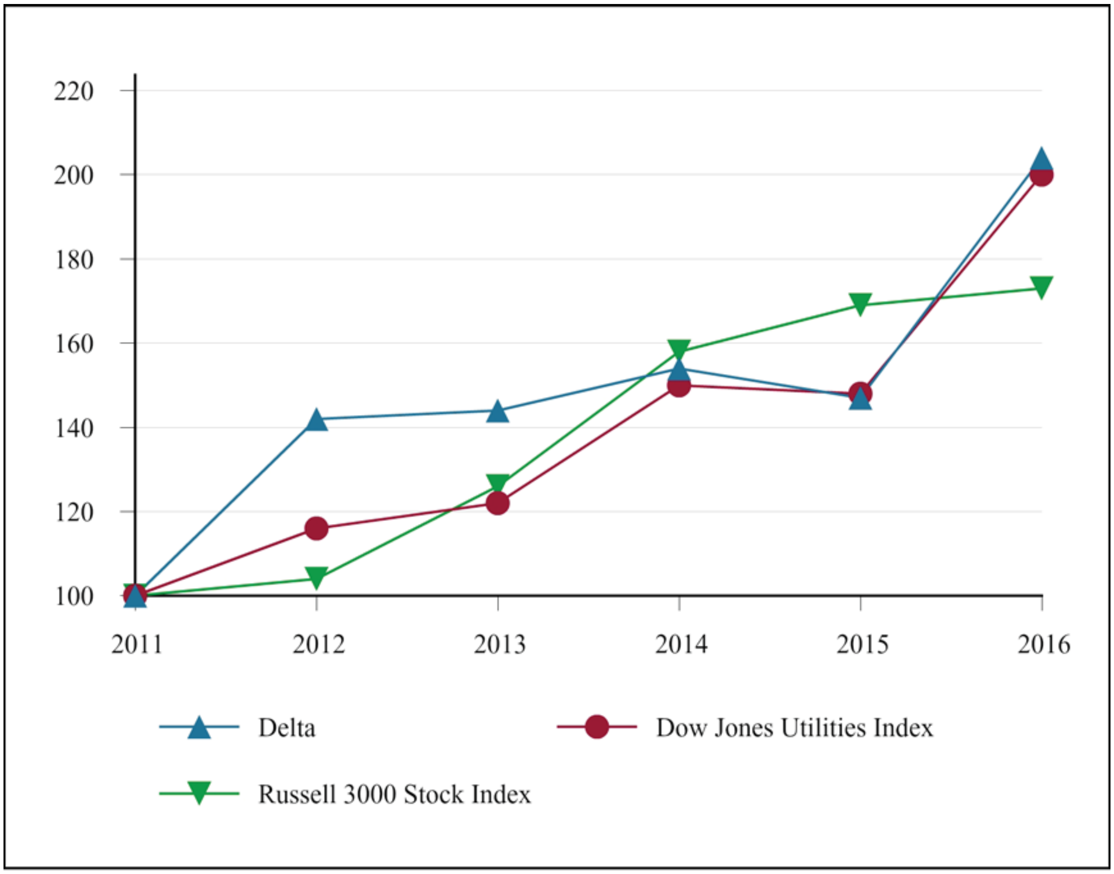
Our common stock is listed on NASDAQ and trades under the symbol "DGAS". There were 1,381 record holders of our common stock as of August 26, 2016. The accompanying table sets forth, for the periods indicated, the high and low sales prices for the common stock on the NASDAQ stock market and the cash dividends declared per share.

	Range of Stock Prices ($)		Dividends
Quarter	High	Low	Per Share ($)
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
Fiscal 2015			
First	22.58	19.50	.20
Second	21.54	19.50	.20
Third	21.39	19.10	.20
Fourth	20.84	19.39	.20

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.

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, 2011 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.



	2011	2012	2013	2014	2015	2016
Delta	100	142	144	154	147	204
Dow Jones Utilities Index	100	116	122	150	148	200
Russell 3000 Stock Index	100	104	126	158	169	173

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,	2016	2015	2014	2013	2012
Summary of Operations ($)					
Operating revenues	64,130,220	86,188,238	95,845,871	80,664,837	74,078,322
Operating income	11,433,992	12,963,861	15,603,439	13,188,679	13,265,228
Net income	5,529,378	6,496,081	8,275,128	7,200,776	5,783,998
Earnings per common share					
Basic and diluted	.78	.92	1.19	1.05	.85
Cash dividends declared per common share	.82	.80	.76	.72	.70
Weighted Average Number of Common Shares					
Basic and Diluted	7,066,925	7,002,694	6,918,725	6,843,455	6,777,186
Total Assets ($) (a)	188,879,129	187,711,166	185,934,857	183,832,911	182,791,259
Capitalization ($)					
Common shareholders' equity	77,726,969	77,221,654	74,728,352	70,005,415	66,220,407
Long-term debt (a)	50,422,796	51,916,296	53,409,696	54,902,896	56,395,896
Total capitalization (a)	128,149,765	129,137,950	128,138,048	124,908,311	122,616,303
Short-Term Debt ($) (b)	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
Other Items ($)					
Capital expenditures	6,302,666	9,010,876	8,077,642	7,179,473	7,337,115
Property, plant and equipment	241,833,771	236,780,490	229,367,319	223,545,925	217,172,542

(a) In 2016, we adopted new guidance related to the presentation of debt issuance costs on the consolidated balance sheets. As a result of the adoption, total assets, long-term debt and total capitalization were reclassified to conform to the new presentation, each of which were reduced by $83,704, $90,304, $97,104 and $104,104 for 2015, 2014, 2013 and 2012, respectively. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 for additional information.

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

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

Overview of 2016 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 2016. 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 $0.78 for 2016 decreased, as compared to our consolidated income of $0.92 for 2015, due to decreased revenue, net of natural gas costs from the sale of natural gas and natural gas liquids by our non-regulated segment (as further discussed in Results of Operations). Our non-regulated segment experienced decreased revenues, net of natural gas costs, due to decreased sales prices resulting from decreased market prices for both natural gas and natural gas liquids. Our regulated segment is not exposed to the same price risk from market prices as our natural gas cost recovery tariff allows us to pass the cost of natural gas through to our regulated customers. However, our regulated segment experienced decreased revenues, net of natural gas costs resulting from a decline in volumes sold due to the weather being 24% warmer than the prior year, which is partially offset by amounts recovered from our residential and small non-residential customers through our weather normalization tariff.

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 rate making where our base rates are established to recover based on 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 differs from 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 2017. 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.

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, 2017 and permits borrowings up to $40,000,000. There were no borrowings outstanding on the bank line of credit as of June 30, 2016 or June 30, 2015.

Cash and cash equivalents were $18,607,000 at June 30, 2016 compared with $16,924,000 at June 30, 2015 and $13,676,000 at June 30, 2014. These changes in cash and cash equivalents are summarized in the following table:

$(000)	2016	2015	2014
Provided by operating activities	$ 14,738	18,746	17,340
Used in investing activities	(6,087)	(8,910)	(7,870)
Used in financing activities	(6,969)	(6,588)	(6,155)
Increase in cash and cash equivalents	1,682	3,248	3,315

In 2016, cash provided by operating activities decreased $4,008,000 (21%) 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 in the current year.

In 2015, cash provided by operating activities increased $1,406,000 (8%), as compared to 2014, due to decreased cash paid for income taxes as a result of decreased earnings in the current year, which were partially offset by decreased cash received from the sale of natural gas liquids.

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

In 2016 and 2015 there were no significant changes in cash used in financing activities, as compared to 2015 and 2014, 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 2017 to be approximately $8.5 million.

The following is provided to summarize our contractual cash obligations for indicated periods after June 30, 2016:

	Payments Due by Fiscal Year				
$(000)	2017	2018 - 2019	2020 - 2021	After 2021	Total
Interest payments (a)	2,234	4,171	3,915	16,333	26,653
Long-term debt (b)	1,500	3,000	3,000	44,500	52,000
Pension contributions (c)	500	1,000	1,000	4,500	7,000
Natural gas purchases (d)	612	—	—	—	612
Total contractual obligations (e)	4,846	8,171	7,915	65,333	86,265

(a) Our long-term debt, notes payable and customers' deposits all require interest payments. Interest payments are projected based on fiscal 2016 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 2030, as recommended by our actuary.

(d) As of June 30, 2016, our non-regulated segment had forward purchase contracts for natural gas which had minimum purchase obligations that expire in May, 2017. 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 ($43,405,000), regulatory liabilities ($1,138,000), asset retirement obligations ($3,918,000) and deferred compensation ($1,034,000). 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, 2016:

	Requirement	Actual
Tangible net worth	no less than $25,800,000	$76,850,000
Debt to capitalization ratio	no more than 70%	40%
Fixed charge coverage ratio	no less than 1.20x	7.55x
Dividends paid	no more than $48,619,000	$25,278,000

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 rate-making 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, 2016, 2015 and 2014, we recorded pension costs for our defined benefit retirement plan of $812,000, $493,000 and $750,000, 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, 2016, $10,972,000 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 2016 and was based on our targeted asset allocation assumption for 2016 of approximately 70% equity investments and approximately 30% 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 3.50%, and various other assumptions, we estimate that our pension costs associated with our defined benefit retirement plan will increase from $812,000 in 2016 to $1,312,000 in 2017. Modifying the expected long-term rate of return on our defined benefit retirement plan assets by .25% would change pension costs for 2017 by approximately $74,000. Increasing the discount rate assumption by .25% would decrease pension costs by approximately $128,000. Decreasing the discount rate assumption by .25% would increase pension costs by approximately $135,000.

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.

Asset Retirement Obligations

We have accrued asset retirement obligations for natural gas well plugging and abandonment costs. Additionally, we have recorded asset retirement obligations required pursuant to regulations related to the retirement of our service lines and mains, although the timing of such retirements is uncertain. The fair value of our retirement obligations is recorded at the time the obligations are incurred. We do not recognize asset retirement obligations relating to assets with indeterminate useful lives. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time the liabilities accrete for the change in their present value, and the initial capitalized costs depreciate over the useful lives of the related assets. For asset retirement obligations attributable to assets of our regulated segment, the accretion and depreciation are deferred as a regulatory asset. We must use judgment to identify all appropriate asset retirement obligations. The underlying assumptions used for the value of the retirement obligations and related capitalized costs can change from period to period. These assumptions include the estimated future retirement costs, the estimated retirement dates and the assumed credit-adjusted risk-free interest rates. Our asset retirement obligations are further discussed in Note 4 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations and the other sections of this report contain forward-looking statements that relate to future events or our future performance. We have attempted to identify these statements by using words such as “estimates”, “attempts”, “expects”, “monitors”, “plans”, “anticipates”, “intends”, “continues”, “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 margin can be derived directly from our Consolidated Statements of Income included in Item 8, as follows:

($000)	2016	2015	2014
Operating revenues	64,130	86,188	95,846
Regulated purchased natural gas	(11,704)	(22,729)	(27,215)
Non-regulated purchased natural gas	(17,621)	(26,713)	(29,059)
Consolidated gross margins	34,805	36,746	39,572

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 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)	2016 compared to 2015	2015 compared to 2014
Increase (decrease) in gross margins		
Regulated segment		
Natural gas sales	(484)	(228)
Natural gas transportation	(141)	203
Other	(67)	(34)
Intersegment elimination (a)	278	172
Total	(414)	113
Non-regulated segment		
Natural gas sales	(616)	(1,601)
Natural gas liquids	(578)	(1,111)
Other	(55)	(55)
Intersegment elimination (a)	(278)	(172)
Total	(1,527)	(2,939)
Decrease in consolidated gross margins	(1,941)	(2,826)
(%)		
Percentage increase (decrease) in volumes		
Regulated segment		
Natural gas sales (Mcf)	(20)	(3)
Natural gas transportation (Mcf)	3	3
Non-regulated segment		
Natural gas sales (Mcf)	1	2
Natural gas liquids (gallons)	(22)	(1)

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

Heating degree days were 83% of the normal thirty-year average temperatures for fiscal 2016, as compared with 110% and 107% of normal temperatures for 2015 and 2014, 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 2016, consolidated gross margins decreased $1,941,000 (5%), as compared to 2015, primarily due to decreased non-regulated gross margins. Non-regulated gross margins decreased as a result of decreased gross margins on natural gas sales and natural gas liquids. Gross margins on non-regulated natural gas sales decreased due to decreased sales prices partially offset by decreased natural gas costs. Gross margins on the sale of natural gas liquids decreased due to a 72% decline in the average sales price. Although our regulated segment experienced decreased volumes sold as a result of warmer weather, this decrease was partially offset by increased rates billed through our weather normalization tariff and our pipe replacement program tariff.

In 2015, consolidated gross margins decreased $2,826,000 (7%), as compared to 2014, 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 2016 and 2015, there were no significant changes in operation and maintenance and depreciation and amortization, as compared to 2015 and 2014, respectively.

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

In 2015, taxes other than income taxes increased $472,000 (20%) primarily due to an increase in property taxes resulting from an increase in the assessed value of our property.

Other Income

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

In 2015, other income decreased $176,000 (88%) due to a decrease in the earnings from the supplemental retirement trust and a decrease in interest received on the cash surrender value of our life insurance policies. The decrease in the earnings from the supplemental retirement trust was offset by a decrease in operating expense resulting from a corresponding change in the liability of the trust.

Interest Charges

In 2016 and 2015, there were no significant changes in interest on long-term debt, amortization of debt expense and other interest expense, as compared to 2015 and 2014, respectively.

Income Tax Expense

In 2016 and 2015, income tax expense decreased $515,000 (13%) and $967,000 (20%) due to decreases in net income before income taxes, as compared to 2015 and 2014, respectively. There were no significant changes in our effective tax rate for 2016 and 2015, as compared to 2015 and 2014, respectively.

Basic and Diluted Earnings Per Common Share

For 2016 and 2015, our basic and diluted earnings per common share changed, as compared to 2015 and 2014, 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, 2016, we had forward purchase contracts through May, 2017 totaling $612,000 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, 2016 or June 30, 2015. As of June 30, 2016 and June 30, 2015, the weighted average interest rate on our bank line of credit was 1.5% and 1.4%, respectively. During 2016, we did not have any borrowings on our bank line of credit. During 2015, we borrowed and repaid $126,000 from the bank line of credit, having a weighted average interest rate of 1.3%. A one percent (one hundred basis point) increase in our average interest rate would not have had a significant impact on our annual pre-tax net income.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULE

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 Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2016 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, 2016 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, 2016 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, 2016.

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, 2016, 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 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, 2016, 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 of the Company as of and for the year ended June 30, 2016 and our report dated August 26, 2016 expressed an unqualified opinion on those financial statements and the financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
August 26, 2016

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 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2016. 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 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2016. 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, 2016:

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)
—	—	747,275

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 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2016. 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 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2016. 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 2016 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission no later than 120 days after June 30, 2016. 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.
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.
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.
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	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.
10.27	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.
10.28	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.

10.29	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.
10.30	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.
10.31	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.
10.32	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.
10.33	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.
10.34	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.
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, 2016, 2015 and 2014;
- (iii) Consolidated Statements of Cash Flows for the years ended June 30, 2016, 2015 and 2014;
- (iv) Consolidated Balance Sheets as of June 30, 2016 and 2015;
- (v) Consolidated Statements of Changes in Shareholders' Equity for the years ended June 30, 2016, 2015 and 2014;
- (vi) Notes to Consolidated Financial Statements;
- (vii) Schedule II – Valuation and Qualifying Accounts for the years ended June 30, 2016, 2015 and 2014.

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 26th day of August, 2016.

DELTA NATURAL GAS COMPANY, INC.

By: /s/Glenn R. Jennings

Glenn R. Jennings

Chairman of the Board, President and Chief Executive Officer

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

(i) Principal Executive Officer:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 26, 2016

(ii) Principal Financial Officer:

/s/John B. Brown (John B. Brown)	Chief Operating Officer, Treasurer and Secretary	August 26, 2016

(iii) Principal Accounting Officer:

/s/Matthew D. Wesolosky (Matthew D. Wesolosky)	Vice President - Controller	August 26, 2016

(iv) A Majority of the Board of Directors:

/s/Glenn R. Jennings (Glenn R. Jennings)	Chairman of the Board, President and Chief Executive Officer	August 26, 2016
/s/Linda K. Breathitt (Linda K. Breathitt)	Director	August 26, 2016
/s/Jacob P. Cline III (Jacob P. Cline, III)	Director	August 26, 2016
/s/Sandra C. Gray (Sandra C. Gray)	Director	August 26, 2016
/s/Edward J. Holmes (Edward J. Holmes)	Director	August 26, 2016
/s/Michael J. Kistner (Michael J. Kistner)	Director	August 26, 2016
/s/Fred N. Parker (Fred N. Parker)	Director	August 26, 2016
/s/Rodney L. Short (Rodney L. Short)	Director	August 26, 2016
/s/Arthur E. Walker, Jr. (Arthur E. Walker, Jr.)	Director	August 26, 2016

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, 2016 and 2015, 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, 2016. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Delta Natural Gas Company, Inc. and subsidiaries as of June 30, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2016, 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.

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, 2016, 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 August 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
August 26, 2016

Delta Natural Gas Company, Inc.

Consolidated Statements of Income

For the Year Ended June 30,	2016	2015	2014
Operating Revenues			
Regulated revenues	$ 41,242,094	$ 52,681,120	$ 57,054,180
Non-regulated revenues	22,888,126	33,507,118	38,791,691
Total operating revenues	$ 64,130,220	$ 86,188,238	$ 95,845,871
Operating Expenses			
Regulated purchased natural gas	$ 11,704,178	$ 22,728,766	$ 27,215,425
Non-regulated purchased natural gas	17,621,069	26,713,424	29,059,426
Operation and maintenance	13,989,510	14,608,835	15,495,537
Depreciation and amortization	6,416,221	6,377,743	6,147,618
Taxes other than income taxes	2,965,250	2,795,609	2,324,426
Total operating expenses	$ 52,696,228	$ 73,224,377	$ 80,242,432
Operating Income	$ 11,433,992	$ 12,963,861	$ 15,603,439
Other Income	$ 4,124	$ 25,097	$ 201,462
Interest Charges			
Interest on long-term debt	$ 2,245,224	$ 2,309,124	$ 2,373,024
Other interest expense	52,533	51,538	51,563
Amortization of debt expense	233,500	240,000	246,600
Total interest charges	$ 2,531,257	$ 2,600,662	$ 2,671,187
Net Income Before Income Taxes	$ 8,906,859	$ 10,388,296	$ 13,133,714
Income Tax Expense	3,377,481	3,892,215	4,858,586
Net Income	$ 5,529,378	$ 6,496,081	$ 8,275,128
Earnings Per Common Share (Note 11)			
Basic and Diluted	$ .78	$ .92	$ 1.19
Dividends Declared Per Common Share	$ .82	$ .80	$ .76

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,	2016	2015	2014
Cash Flows From Operating Activities			
Net income	$ 5,529,378	$ 6,496,081	$ 8,275,128
Adjustments to reconcile net income to net cash from operating activities			
Depreciation and amortization	6,649,721	6,617,743	6,420,525
Deferred income taxes and investment tax credits	1,193,793	1,449,471	(515,492)
Change in cash surrender value of officer's life insurance	6,198	(19,036)	(67,722)
Share-based compensation	452,230	1,095,051	1,111,966
Excess tax deficiency from share-based compensation	(7,581)	(9,574)	(8,967)
(Increase) decrease in assets			
Accounts receivable	1,091,517	871,270	2,216,925
Natural gas in storage	1,344,242	2,491,337	(1,644,186)
Deferred natural gas cost	(674,077)	724,923	3,197,921
Materials and supplies	(4,549)	(12,578)	(288,597)
Prepayments	(1,226,279)	(363,263)	(1,253,798)
Other assets	(288,867)	225,771	11,556
Increase (decrease) in liabilities			
Accounts payable	(1,181,356)	(1,135,821)	169,226
Accrued taxes	106,856	(80,925)	83,528
Asset retirement obligations	(85,068)	375,073	(553,612)
Other liabilities	1,832,112	20,658	185,805
Net cash provided by operating activities	$ 14,738,270	$ 18,746,181	$ 17,340,206
Cash Flows From Investing Activities			
Capital expenditures	$ (6,302,666)	$ (9,010,876)	$ (8,077,642)
Proceeds from sale of property, plant and equipment	275,397	161,311	268,082
Other	(60,000)	(60,000)	(60,000)
Net cash used in investing activities	$ (6,087,269)	$ (8,909,565)	$ (7,869,560)

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,	2016	2015	2014
Cash Flows From Financing Activities			
Dividends on common shares	$ (5,822,259)	$ (5,639,791)	$ (5,289,911)
Issuance of common shares	614,518	532,712	595,249
Excess tax benefit from share-based compensation	2,073	18,823	39,472
Payment of minimum tax withholdings on share-based compensation	(263,044)	—	—
Repayment of long-term debt	(1,500,000)	(1,500,000)	(1,500,000)
Borrowings on bank line of credit	—	126,430	691,157
Repayment of bank line of credit	—	(126,430)	(691,157)
Net cash used in financing activities	$ (6,968,712)	$ (6,588,256)	$ (6,155,190)
Net Increase in Cash and Cash Equivalents	$ 1,682,289	$ 3,248,360	$ 3,315,456
Cash and Cash Equivalents, Beginning of Year	16,924,278	13,675,918	10,360,462
Cash and Cash Equivalents, End of Year	$ 18,606,567	$ 16,924,278	$ 13,675,918
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year for			
Interest	$ 2,298,228	$ 2,369,078	$ 2,436,435
Income taxes (net of refunds)	$ 2,064,005	$ 3,312,944	$ 5,819,956
Significant non-cash transactions			
Accrued capital expenditures	$ 157,808	$ 207,169	$ 328,638

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,	2016	2015
Assets		
Current Assets		
Cash and cash equivalents	$ 18,606,567	$ 16,924,278
Accounts receivable, less accumulated allowances for doubtful accounts of $301,000 and $258,000 in 2016 and 2015, respectively	4,741,595	5,760,550
Natural gas in storage, at average cost (Note 1)	3,289,920	4,634,162
Deferred natural gas costs (Notes 1 and 14)	674,077	—
Materials and supplies, at average cost	544,342	543,563
Prepayments	3,051,665	3,347,187
Total current assets	$ 30,908,166	$ 31,209,740
Property, Plant and Equipment	$ 241,833,771	$ 236,780,490
Less - Accumulated provision for depreciation	(104,192,898)	(98,741,351)
Net property, plant and equipment	$ 137,640,873	$ 138,039,139
Other Assets		
Cash surrender value of life insurance (face amount of $954,000 and $951,000 in 2016 and 2015, respectively)	$ 414,985	$ 421,183
Prepaid pension (Note 6)	—	2,145,969
Regulatory assets (Note 1)	18,881,126	14,917,823
Other non-current assets	1,033,979	977,312
Total other assets	$ 20,330,090	$ 18,462,287
Total assets	$ 188,879,129	$ 187,711,166

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,	2016	2015
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 4,200,298	$ 5,426,395
Current portion of long-term debt (Note 10)	1,500,000	1,500,000
Accrued taxes	1,584,675	1,472,401
Customers' deposits	618,137	600,788
Accrued interest on debt	111,825	112,296
Accrued vacation	756,138	749,031
Regulatory liability - refundable natural gas costs (Note 1)	—	756
Other liabilities	585,342	610,238
Total current liabilities	$ 9,356,415	$ 10,471,905
Long-Term Debt (Notes 1 and 10)	$ 50,422,796	$ 51,916,296
Long-Term Liabilities		
Deferred income taxes	$ 43,405,098	$ 42,130,067
Investment tax credits	—	10,800
Regulatory liabilities (Note 1)	1,138,141	1,137,758
Accrued Pension	1,833,780	—
Asset retirement obligations (Note 4)	3,917,585	3,795,590
Other long-term liabilities	1,078,345	1,027,096
Total long-term liabilities	$ 51,372,949	$ 48,101,311
Commitments and Contingencies (Note 13)		
Total liabilities	$ 111,152,160	$ 110,489,512
Shareholders' Equity		
Common shares ($1.00 par value), 20,000,000 shares authorized; 7,087,762 and 7,026,500 shares outstanding at June 30, 2016 and June 30, 2015, respectively	$ 7,087,762	$ 7,026,500
Premium on common shares	49,472,542	48,735,608
Retained earnings	21,166,665	21,459,546
Total shareholders' equity	$ 77,726,969	$ 77,221,654
Total liabilities and shareholders' equity	$ 188,879,129	$ 187,711,166

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, 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 deficiency 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

	Year Ended June 30, 2014			
	Common Shares	Premium on Common Shares	Retained Earnings	Shareholders' Equity
Balance, beginning of year	$ 6,864,253	$ 45,523,123	$ 17,618,039	$ 70,005,415
Net income	—	—	8,275,128	8,275,128
Issuance of common shares	28,809	566,440	—	595,249
Issuance of common shares under the incentive compensation plan	49,696	299,930	—	349,626
Share-based compensation expense	—	762,340	—	762,340
Tax benefit from share-based compensation	—	30,505	—	30,505
Dividends on common shares	—	—	(5,289,911)	(5,289,911)
Balance, end of year	$ 6,942,758	$ 47,182,338	$ 20,603,256	$ 74,728,352

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.

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)	2016	2015
Regulated segment		
Distribution, transmission and storage	214,660	210,659
General, miscellaneous and intangibles	23,145	22,785
Construction work in progress	1,422	739
Total regulated segment	239,227	234,183
Non-regulated segment	2,607	2,597
Total property, plant and equipment	241,834	236,780

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 2.8% of average depreciable plant for 2016, 2015 and 2014.

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 2016, 2015 or 2014.

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 on the Consolidated Balance Sheets. As of June 30, 2016, unbilled natural gas costs are included in deferred natural gas costs and as of June 30, 2015, unbilled natural gas costs are included in regulatory liability - refundable natural gas costs on the accompanying Consolidated Balance Sheets. Unbilled amounts include the following:

(000)	2016	2015
Unbilled revenues ($)	1,452	1,674
Unbilled natural gas costs ($)	319	462
Unbilled volumes (Mcf)	63	69

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 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)	2016	2015
Regulatory assets		
Current assets		
Deferred natural gas costs	674	—
Other assets		
Conservation/efficiency program expenses	243	173
Loss on extinguishment of debt	2,689	2,916
Asset retirement obligations	5,121	4,668
Accrued pension	10,828	7,161
Total other assets	18,881	14,918
Total regulatory assets	19,555	14,918
Regulatory liabilities		
Current liabilities		
Refundable natural gas costs	—	1
Long-term liabilities		
Accrued cost of removal on long-lived assets	487	417
Regulatory liability for deferred income taxes	651	721
Total long-term liabilities	1,138	1,138
Total regulatory liabilities	1,138	1,139

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 26 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 fully 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 quarterly report ending September 30, 2018 and we are evaluating the methods of adoption allowed by the new standard and the effect the standard is expected to have on our results of operations, financial position and cash flows.

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 and net realizable value. The guideline, 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 lessees to recognize on the statement of financial position a liability for the lease payments and a right-of-use asset representing its 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 and cash flows.

In March, 2016, the Financial Accounting Standards Board issued guidance simplifying the accounting and disclosure requirements for share-based compensation, including the income tax consequences, classification of the awards as equity or liability and classification on the statement of cash flows. 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.

Recently Adopted Pronouncements

In June, 2014, the Financial Accounting Standards Board issued guidance on share-based payments where performance targets can be achieved subsequent to the requisite service period. In such instances, the guidance requires the performance target to be excluded from the determination of the grant date fair value and, when it is probable the performance target will be met, recognition of compensation cost attributable to the periods which the requisite service has already been rendered. The guidance did not impact any share-based payment awards outstanding, thus the guidance is adopted prospectively for all share-based payment awards granted after June 30, 2016 and did not impact our results of operations, financial position and cash flows.

In April, 2015, the Financial Accounting Standards Board issued guidance on the presentation of debt issuance costs which requires the debt issuance costs to be recognized as a direct deduction from the carrying amount of the debt liability as debt issuance costs do not represent assets, but rather adjustments to the carrying cost of debt. We adopted the guidance retrospectively to June 30, 2015. The implementation of this guidance resulted in a $77,000 and $84,000 reduction to long-term debt on the accompanying Consolidated Balance Sheets as of June 30, 2016 and 2015, respectively, representing amounts previously reported as unamortized debt expense. The adoption of the guidance did not have a material effect on our results of operations, financial position and cash flows.

In May, 2015, the Financial Accounting Standards Board issued guidance simplifying the disclosure of certain investments measured using the net asset value per share of the investment. The guidance provides for a practical expedient where investments measured at net asset value per share should not be categorized within the fair value hierarchy (i.e., as Level 1, 2 or 3). Adoption of the guidance did not impact our results of operations, financial position and cash flows.

In November, 2015, the Financial Accounting Standards Board issued guidance to simplify the presentation of deferred income taxes on the balance sheet by classifying all deferred tax assets and liabilities as non-current. As a result of the standard, we have presented all deferred tax liabilities and assets, net, as non-current in deferred income taxes on the accompanying Consolidated Balance Sheets, retrospectively for all periods presented. The adoption of this standard resulted in a $442,000 and $141,000 reclassification of current deferred income tax liability to long-term deferred income tax liability for 2016 and 2015, respectively. Note 5 of the Notes to Consolidated Financial Statements further discusses our income taxes.

(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)	2016	2015
Money market	44	27
U.S. equity securities	435	395
Foreign equity funds	168	185
U.S. fixed income funds	223	177
Foreign fixed income funds	19	57
Absolute return strategy mutual funds	145	136
Total trust assets	1,034	977

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.

	2016		2015	
($000)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
4.26% Series A Notes	51,923	55,324	53,416	52,935

(4) Asset Retirement Obligations

Legal obligations

As of June 30, 2016 and 2015, 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)	2016	2015
Balance, beginning of year	3,796	3,261
Liabilities incurred	28	21
Liabilities settled	(266)	(232)
Accretion	271	246
Revisions in estimated cash flows	89	500
Balance, end of year	3,918	3,796

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, $487,000 and $417,000 of such accrued cost of removal was recorded as a regulatory liability on the accompanying Consolidated Balance Sheets as of June 30, 2016 and 2015, 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)	2016	2015
Deferred Tax Liabilities		
Deferred natural gas cost	(256)	—
Prepaid expenses	(392)	(452)
Accelerated depreciation	(38,862)	(38,108)
Prepaid pension	—	(805)
Regulatory assets - asset retirement obligations	(981)	(876)
Regulatory assets - loss on extinguishment of debt	(1,021)	(1,107)
Regulatory assets - unrecognized accrued pension	(4,110)	(2,718)
Regulatory liabilities	(837)	(1,268)
Other	(1,084)	(1,119)
Total deferred tax liabilities	(47,543)	(46,453)
Deferred Tax Assets		
Bad debt reserve	114	98
Accrued pension	516	—
Accrued employee benefits	875	1,131
Asset retirement obligations	1,425	1,378
Investment tax credits	—	7
Regulatory liabilities	1,084	1,540
Section 263(a) capitalized costs	32	64
Other	92	105
Total deferred tax assets	4,138	4,323
Net accumulated deferred income tax liability	(43,405)	(42,130)

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

($000)	2016	2015	2014
Current			
Federal	1,817	1,950	4,532
State	366	493	842
Total	2,183	2,443	5,374
Deferred	1,194	1,449	(515)
Income tax expense	3,377	3,892	4,859

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

(%)	2016	2015	2014
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)	(0.1)
Other differences, net	—	(0.4)	(0.9)
Effective income tax rate	37.9	37.5	37.0

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, 2016 and 2015, we did not have any unrecognized tax positions, which, if recognized, would impact the effective tax rate.

The following is a reconciliation of our unrecognized tax benefits:

($000)	2016	2015
Balance, beginning of year	5	64
Gross decreases - tax positions in prior period	(5)	(59)
Balance, end of year	—	5

We file income tax returns in federal and Kentucky jurisdictions. Tax years previous to June 30, 2013 and June 30, 2012 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, 2016 and June 30, 2015, respectively, are as follows:

($000)	2016	2015
Change in Benefit Obligation		
Benefit obligation at beginning of year	28,838	26,383
Service cost	1,004	990
Interest cost	1,157	1,056
Actuarial loss	1,517	1,219
Benefits paid	(944)	(810)
Benefit obligation at end of year	31,572	28,838
Change in Plan Assets		
Fair value of plan assets at beginning of year	30,984	29,675
Actual return on plan assets	(802)	1,119
Employer contributions	500	1,000
Benefits paid	(944)	(810)
Fair value of plan assets at end of year	29,738	30,984
Recognized Amounts		
Projected benefit obligation	(31,572)	(28,838)
Plan assets at fair value	29,738	30,984
Funded status	(1,834)	2,146
Net amount recognized as (accrued) prepaid pension on the Consolidated Balance Sheets	(1,834)	2,146
Items Not Yet Recognized as a Component of Net Periodic Benefit Cost		
Prior service cost	(144)	(230)
Accumulated net losses	10,972	7,391
Amounts recognized as regulatory assets	10,828	7,161

The accumulated benefit obligation was $28,124,000 and $25,012,000 for 2016 and 2015, respectively.

($000)	2016	2015	2014
Components of Net Periodic Benefit Cost			
Service cost	1,004	990	1,023
Interest cost	1,157	1,056	1,038
Expected return on plan assets	(1,636)	(1,711)	(1,567)
Amortization of unrecognized net loss	373	244	342
Amortization of prior service cost	(86)	(86)	(86)
Net periodic benefit cost	812	493	750

(%)	2016	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations			
Discount rate	3.5	4.25	4.25
Rate of compensation increase	4.0	4.0	4.0
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost			
Discount rate	4.25	4.25	4.5
Expected long-term return on plan assets	5.5	6.0	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 70% equity investments and 30% 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	2016	2015
Asset Class			
Cash and cash equivalents	3	3	3
Equity Securities			
U.S. equity securities	54	48	47
Foreign equity securities	21	10	12
	75	58	59
Fixed Income Securities			
U. S. fixed income security	13	22	18
Foreign fixed income security	2	3	6
	15	25	24
Other Securities			
Absolute return strategy mutual funds	7	14	14
	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)	2016	Level 1	Level 2	Level 3
Asset Class				
Cash	807	807	—	—
Equity Securities				
U.S. equity securities	14,398	14,398	—	—
Foreign equity securities	2,993	2,993	—	—
	17,391	17,391	—	—
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	842	—	842	—
	7,240	5,408	1,832	—
Other				
Absolute return strategy mutual funds	4,300	4,300	—	—
Total investments at fair value	29,738	27,906	1,832	—

($000)	2015	Level 1	Level 2	Level 3
Asset Class				
Cash	1,072	1,072	—	—
Equity Securities				
U.S. equity securities	14,602	14,602	—	—
Foreign equity securities	3,690	3,690	—	—
	18,292	18,292	—	—
Fixed Income Securities				
U.S. treasury securities	524	524	—	—
U.S. corporate bonds	902	—	902	—
High yield funds	3,284	3,284	—	—
Foreign bond funds	1,857	1,857	—	—
Other	734	—	734	—
	7,301	5,665	1,636	—
Other				
Absolute return strategy mutual funds	4,319	4,319	—	—
Total investments at fair value	30,984	29,348	1,636	—

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 a $500,000 discretionary contribution to the defined benefit retirement plan in fiscal 2016. In August, 2016, we made a $1,000,000 discretionary contribution to the defined benefit retirement plan and expect to make an additional $500,000 discretionary contribution to the defined benefit retirement plan in fiscal 2017.

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

($000)	
2017	3,020
2018	1,556
2019	1,639
2020	1,244
2021	1,155
2022 - 2026	8,365

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 2016, 2015 and 2014, our employee savings plan expense was $379,000, $359,000 and $350,000, 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 2016, 2015 and 2014, Delta contributed $60,000 each year to the trust. As of June 30, 2016 and 2015, the irrevocable trust assets are $1,034,000 and $977,000, 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 28,437, 26,412 and 28,809 shares in 2016, 2015 and 2014, respectively. We registered 400,000 shares for issuance under the Reinvestment Plan in 2006, and as of June 30, 2016 there were approximately 38,000 shares available for issuance.

(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, 2016 and June 30, 2015. During 2016, we did not have any borrowing on our bank line of credit. The maximum amount borrowed during 2015 was $126,000. The bank line of credit extends through June 30, 2017. 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)	
2017	1,500
2018	1,500
2019	1,500
2020	1,500
Thereafter	46,000
Total maturing debt	52,000

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, 2016 and 2015, $77,000 and $84,000 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, 2016 and 2015, we had loss on extinguishment of debt of $2,689,000 and $2,916,000, 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:

	2016	2015	2014
Numerator - Basic and Diluted ($000)			
Net income	5,529	6,496	8,275
Dividends paid	(5,822)	(5,640)	(5,290)
Undistributed earnings (loss)(a)	(293)	856	2,985
Allocated to common shares:			
Undistributed earnings (loss) (a)	(293)	851	2,966
Dividends paid (b)	5,798	5,609	5,263
Earnings allocated to common shares	5,505	6,460	8,229
Denominator - Basic and Diluted			
Weighted average common shares (c)	7,066,925	7,002,694	6,918,725
Earnings per Common Share - Basic and Diluted ($)	0.78	0.92	1.19

(a) Percentage allocated to common shares:

	2016	2015	2014
Weighted average:			
Common shares outstanding	7,066,925	7,002,694	6,918,725
Unvested participating shares outstanding (d)	—	45,500	44,750
Total	7,066,925	7,048,194	6,963,475
Percentage allocated to common shares	100.0%	99.4%	99.4%
Undistributed earnings (loss) ($000)	(293)	856	2,985
Allocated to common shares	(293)	851	2,966

(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, 2016, 2015 and 2014.

(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, 2016, there were 28,000 participating shares outstanding which were excluded from the computation of earnings allocated to common shares for 2016, 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 and 2014. There were 28,000, 65,000 and 74,000 unvested participating shares outstanding as of June 30, 2016, 2015 and 2014, 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 $78,000, $69,000 and $68,000 for the years ended June 30, 2016, 2015 and 2014, 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 or lump sum payments and the continuation of specified benefits over varying periods in certain cases following defined changes in ownership of the Company. In the event all of these agreements were exercised in the form of lump sum payments, approximately $4.4 million would be paid in addition to continuation of specified benefits for up to five years. Additionally, upon a change in control, all unvested shares awarded under our Incentive Compensation Plan, as further discussed in Note 16 of the Notes to Consolidated Financial Statements, would immediately vest.

We are not a party to any material pending legal proceedings.

We have entered into forward purchase agreements for a portion of our non-regulated segment's natural gas purchases through May, 2017. 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-regulatled customers' natural gas requirements. The agreements have aggregate minimum purchase obligations of $612,000 for our fiscal year ending June 30, 2017.

(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 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.

(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 2016. Our largest customer provided approximately $11,555,000, $17,852,000 and $12,569,000 of non-regulated revenues during 2016, 2015 and 2014, respectively. Our second largest customer provided approximately $5,656,000, $7,127,000 and $9,494,000 of non-regulated revenues during 2016, 2015 and 2014, 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 Atmos Energy Marketing and Midwest Energy Services in 2016 and 2015. In 2014, we purchased approximately 98% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services.

Our non-regulated segment purchased approximately 99% of its natural gas from Atmos Energy Marketing and Midwest Energy Services in 2016. In 2015, we purchased approximately 99% of our natural gas from Atmos Energy Marketing, M & B Gas Services and Midwest Energy Services. In 2014, we purchased approximately 96% of our natural gas from Atmos Energy Marketing and M&B Services.

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)	2016	2015	2014
Operating Revenues			
Regulated			
External customers	41,242	52,681	57,054
Intersegment	3,591	3,869	4,041
Total Regulated	44,833	56,550	61,095
Non-regulated			
External customers	22,888	33,507	38,792
Eliminations for intersegment	(3,591)	(3,869)	(4,041)
Total operating revenues	64,130	86,188	95,846
Operating Expenses			
Regulated			
Purchased natural gas	11,704	22,729	27,215
Depreciation and amortization	6,328	6,293	6,068
Other	16,033	15,819	15,285
Total regulated	34,065	44,841	48,568
Non-regulated			
Purchased natural gas	17,621	26,713	29,059
Depreciation and amortization	88	84	80
Other	4,513	5,455	6,576
Total non-regulated	22,222	32,252	35,715
Eliminations for intersegment	(3,591)	(3,869)	(4,041)
Total operating expenses	52,696	73,224	80,242
Other Income			
Regulated	4	25	183
Non-regulated	—	—	18
Total other income	4	25	201
Interest Charges			
Regulated	2,486	2,551	2,633
Non-regulated	45	50	38
Total interest charges	2,531	2,601	2,671
Income Tax Expense			
Regulated	3,238	3,553	3,907
Non-regulated	139	339	952
Total income tax expense	3,377	3,892	4,859
Net Income			
Regulated	4,982	5,748	6,407
Non-regulated	547	748	1,868
Total net income	5,529	6,496	8,275
Assets			
Regulated	185,634	183,482	181,440
Non-regulated	3,245	4,229	4,495
Total assets	188,879	187,711	185,935
Capital Expenditures			
Regulated	6,293	8,991	8,078
Non-regulated	10	20	—
Total capital expenditures	6,303	9,011	8,078

(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, 2016, approximately 747,000 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.

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. Our share-based compensation expense was $452,000, $1,095,000 and $1,112,000 for 2016, 2015 and 2014, respectively.

To the extent the cumulative deduction for income tax purposes exceeds the cumulative compensation expense recognized for financial reporting purposes, the excess tax benefits can be utilized to offset tax deficiencies related to share-based compensation in subsequent periods. In 2016 and 2015, immaterial differences between compensation expense for financial reporting purposes and income tax purposes were recognized.

Stock Awards

In 2016, common stock was awarded to Delta's directors having grant date fair value of $169,000 (8,400 shares). In 2015 and 2014, common stock was awarded to virtually all Delta employees and directors having grant date fair values of $443,000 (22,000 shares) and $350,000 (17,000 shares), respectively. 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 2016, 2015 and 2014, performance shares were awarded to the Company's executive officers having grant date fair values of $787,000 (39,000 shares), $773,000 (39,000 shares) and $801,000 (39,000 shares), respectively. 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. For 2016, 2015 and 2014, compensation expense related to the performance shares was $283,000, $652,000 and $762,000, respectively.

The performance objectives for the performance shares awarded in 2016 were not satisfied and the awards were forfeited. Performance objectives for the performance shares awarded in 2014 and 2015 were met and 28,000 of these shares remain unvested as of June 30, 2016. The Company will recognize the remaining $49,000 of expense associated with these shares between 2017 and 2019.

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 2014 and 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, 2016 is 0.7 years.

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, 2015	65,000	20.47
Granted (a)	39,000	20.17
Vested	(37,000)	20.70
Forfeited	(39,000)	20.17
Unvested shares at June 30, 2016	28,000	20.15

(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.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings (Loss) per Common Share
Fiscal 2016				
September 30	$ 10,393,423	$ (132,549)	$ (524,457)	$ (0.08)
December 31	16,673,347	3,478,479	1,803,351	0.25
March 31	26,202,462	7,084,268	3,983,441	0.56
June 30	10,860,988	1,003,794	267,043	0.05
Fiscal 2015				
September 30	$ 13,321,305	$ 160,061	$ (311,125)	$ (0.05)
December 31	25,875,266	4,899,101	2,656,534	0.38
March 31	35,085,307	7,286,400	4,155,136	0.59
June 30	11,906,360	618,299	(4,464)	—

(18) Subsequent Events

In August, 2016, 9,600 shares of common stock were awarded to outside directors having a grant date fair value of $247,000. In August, 2016, performance shares were awarded to the Company's executive officers. The performance share awards vest only if the performance objective of the awards is met, which is based on the Company's fiscal 2017 audited earnings per share, before any cash bonuses or share-based compensation. Subject to further limitations described in the Plan, all performance shares paid shall be in the form of unvested shares, which contain a service condition whereby recipients of the awards shall vest in one-third increments each year beginning on August 31, 2017, and annually each August 31 thereafter until fully vested as long as the recipient is an employee 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 maximum number of shares which could be issued under the performance awards is 41,000, having a grant date fair value of $1,056,000.

SCHEDULE II

DELTA NATURAL GAS COMPANY, INC.

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED JUNE 30, 2016, 2015 and 2014

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, 2016	$ 258,400	$ 247,724	$ 122,364	$ 327,792	$ 300,696
June 30, 2015	360,000	170,631	237,267	509,498	258,400
June 30, 2014	536,255	107,131	225,502	508,888	360,000

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

	2016	2015	2014	2013	2012
Earnings					
Net income	$ 5,529,378	$ 6,496,081	$ 8,275,128	$ 7,200,776	$ 5,783,998
Provisions for income taxes (a)	3,377,481	3,892,215	4,858,586	4,268,784	3,258,144
Fixed charges	2,557,257	2,623,662	2,694,187	2,770,935	4,321,256
Total	$ 11,464,116	$ 13,011,958	$ 15,827,901	$ 14,240,495	$ 13,363,398
Fixed Charges					
Interest on debt (a)	$ 2,297,757	$ 2,360,662	$ 2,424,587	$ 2,493,135	$ 3,969,025
Amortization of debt expense	233,500	240,000	246,600	253,800	329,231
One third of rental expense	26,000	23,000	23,000	24,000	23,000
Total	$ 2,557,257	$ 2,623,662	$ 2,694,187	$ 2,770,935	$ 4,321,256
Ratio of earnings to fixed charges	4.48x	4.96x	5.87x	5.14x	3.09x

(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.

EXHIBIT 23

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 August 26, 2016, relating to the consolidated financial statements and the 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 the Annual Report on Form 10-K of Delta Natural Gas Company, Inc. for the year ended June 30, 2016.

/s/ DELOITTE & TOUCHE LLP

Atlanta, Georgia
August 26, 2016

EXHIBIT 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

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

I, Glenn R. Jennings, certify that:

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

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

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

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

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

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

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

DATE: August 26, 2016

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

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

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

I, John B. Brown, certify that:

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

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

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

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

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

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

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

DATE: August 26, 2016

/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, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Glenn R. Jennings, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

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

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

DATE: August 26, 2016

/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, 2016 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: August 26, 2016

/s/John B. Brown

John B. Brown
Chief Operating Officer, Treasurer and Secretary

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Exhibit 13-5

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.

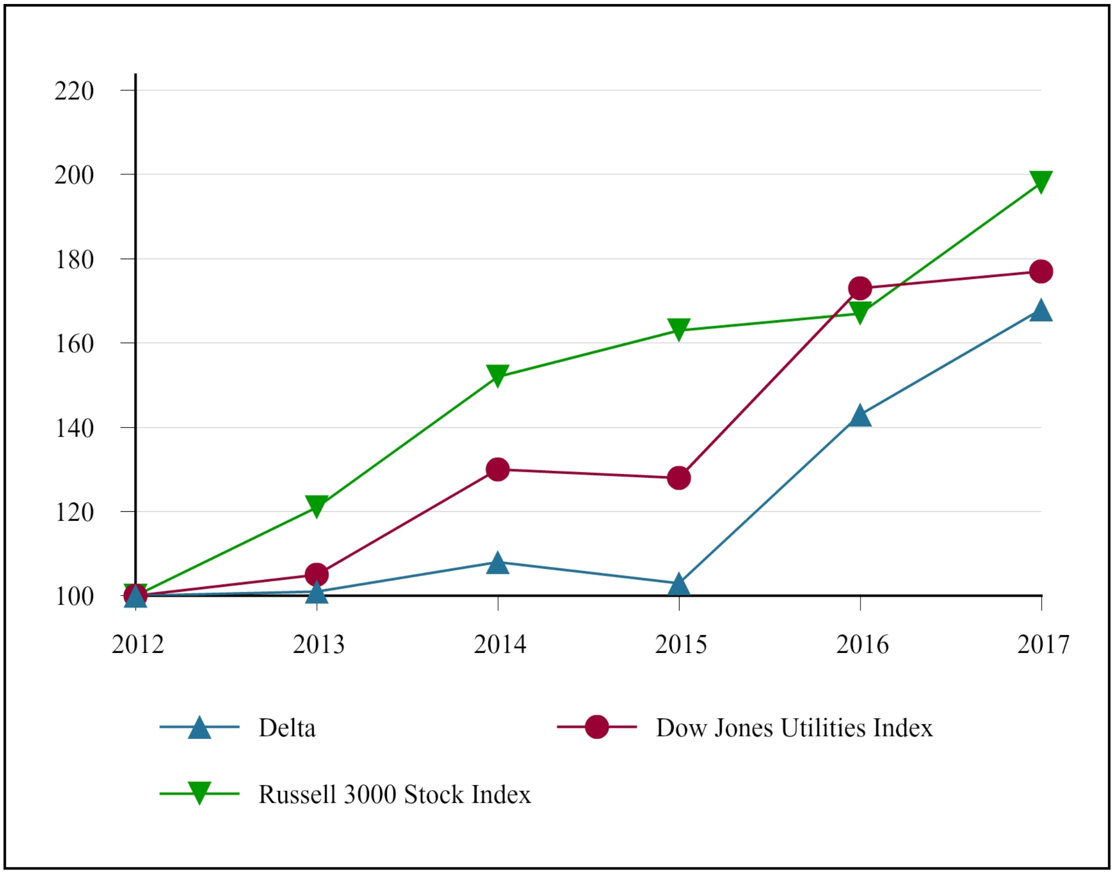
	Range of Stock Prices ($)		Dividends
	High	Low	Per Share ($)
Quarter			
Fiscal 2017			
First	27.36	23.19	.2075
Second	31.29	22.06	.2075
Third	30.85	25.00	.2075
Fourth	30.82	29.70	.415 (a)
Fiscal 2016			
First	20.75	19.96	.205
Second	21.38	20.26	.205
Third	23.70	20.83	.205
Fourth	28.22	22.11	.205

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULE

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 Allocations	Actual 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:

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.

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

DELTA NATURAL GAS COMPANY, INC.
STRATEGIC PLAN
FEBRUARY 22, 2018

Mission Statement

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

Delta accomplishes this mission by utilizing the following strategies:

1. Maintain strong ethical relationships with customers, employees, investors, suppliers, regulatory and governmental entities and other stakeholders including the communities Delta serves

2. Maintain reasonable long-term cash flow

3. Ensure system and supply integrity

4. Pursue growth that provides a positive economic impact on stakeholders

5. Promote efficient energy utilization and environmentally responsible operations

6. Pursue safety for employees, customers and the communities Delta serves

7. Promote, maintain and improve the competitive advantages of the Company's products and services

8. Conduct all business efforts, operations and financial reporting in an ethical and appropriately risk controlled manner and in compliance with applicable statutory, environmental and regulatory requirements

Time Focus
S - Shorter time frame (Current emphasis with 1 to 3 year focus)
L - Longer time frame (Current emphasis with focus beyond 3 years)

DELTA NATURAL GAS COMPANY, INC.
STRATEGIC PLAN
FEBRUARY 22, 2018

ACTION PLANS

1. Maintain strong ethical relationships with customers, employees, investors, suppliers, regulatory and governmental entities and other stakeholders including the communities Delta serves

	Primary Responsibility	Time Focus
1. Strive for clear, effective, appropriate communications with all affected groups	All Officers	L
2. Continue good interdepartmental communications and cooperation; continue appropriate meetings of employees and involve directors, officers and supervisors as appropriate	All Officers	L
3. Communicate to employees periodically the value of employee benefits; provide competitive benefits where possible while sharing costs with employees where necessary, such as medical coverage	Jenny Croft	L
4. Promote employee involvement with community and public relations	Johnny Caudill	L
5. Provide appropriate employee training, considering regulatory requirements, to maintain a qualified work force	Mary Rupard/ Jenny Croft	S
6. Strive for fair and competitive compensation and benefits for employees; consider appropriate cash bonus compensation	All Officers/ Jenny Croft	L

	Primary Responsibility	Time Focus
7. Monitor employee retirement and savings plans, including investment options, fees and evaluation of investment performance	Glenn Jennings/ John Brown/ Johnny Caudill/ Jenny Croft	S
8. Monitor and update Delta's internet home page to ensure its accuracy and usefulness	David Turpin/ Emily Bennett	S
9. Monitor computer utilization and upgrade computer systems and methods as appropriate	All Officers	S
10. Periodically survey employees to help provide a means for employee input	John Brown/ Jenny Croft	S
11. Periodically complete customer satisfaction surveys in connection with the assessment of public awareness and safety meetings	Mary Rupard	S
12. Continue to provide customer service cards to customers when service is provided, and annually summarize the results of cards received for sharing within the Company	John Brown/ Emily Bennett/ Johnny Caudill	S
13. Promote positive ethical relationships with governmental officials, regulatory agencies and local communities	All Officers	S
14. Continue to provide succession planning and arrange for appropriate transitions in company leadership	All Officers	L

2. Maintain reasonable long-term cash flow

	Primary Responsibility	Time Focus
1. Maintain fair, just and reasonable rates and rate design; balance industrial, economic development, residential and commercial rate concerns to keep rates to all groups competitively priced; consider costs of service in developing rates and changes	Glenn Jennings/ John Brown/ Matt Wesolosky/ Jenny Croft	L
2. Integrate federal income tax changes from the Tax Cuts and Jobs Act into Delta's rates and tariffs, obtain PSC approval and bill the reduced rates to customers	John Brown/ Matt Wesolosky/ Jenny Croft	S

3. Ensure system and supply integrity

		Primary Responsibility	Time Focus
1.	Maintain maximum capability and utilization of the Canada Mountain underground storage field	Don Cartwright/ Robert Cobb	L
2.	Upgrade, rebuild and expand the existing pipeline system as necessary to maintain system integrity, deliverability and dependability	Johnny Caudill/ Jonathan Morphew	L
3.	Connect Delta's systems to additional supply sources, and encourage and assist producers to maintain and increase deliveries to Delta	Don Cartwright	L
4.	Maintain flexible, reliable, secure, economic gas supplies; place emphasis on price stability and utilize appropriate hedging techniques	Don Cartwright	L
5.	Ensure long-term planning for adequate gas supplies to meet current and expected customer requirements	Don Cartwright	L
6.	Maintain processing of gas liquids at optimum levels on Delta's system	Don Cartwright/ Robert Cobb	L

4. Pursue growth that provides a positive economic impact on stakeholders

		Primary Responsibility	Time Focus
1.	Continue feasible expansions of Delta's distribution system with extensions to unserved portions of our service area and to new market areas	Johnny Caudill/ Jeff Steele	S
2.	Pursue economic development and the addition of larger volume customers in Delta's service area	Jeff Steele	L
3.	Maintain and increase the utilization of base, incremental load and off-peak natural gas uses	Johnny Caudill/ Jeff Steele	L
4.	Pursue acquisitions of natural gas distribution, transmission, production and gathering properties	All Officers	L
5.	Pursue increasing system throughput utilizing storage, pipeline, transportation and off-system sales opportunities	Don Cartwright/ Robert Cobb	L
6.	Continue programs to add new customers, through conversions from other energy sources, that are located on Delta's existing gas mains	Johnny Caudill/ Jeff Steele	L
7.	Continue advertising and promotional efforts that utilize funding from pipeline supplier rate cases	Johnny Caudill/ Jeff Steele	S
8.	Pursue compressed natural gas fueling stations on Delta's system	Glenn Jennings/ Johnny Caudill/ Jeff Steele	S
9.	Continue liquids processing operations at Canada Mountain and maximize the utilization and efficiency of the processing plant and liquids sales	Don Cartwright/ Robert Cobb	S
10.	Continue to maximize transportation volumes into Delta's TranEx pipeline from the Somerset pipeline and Vinland pipeline	Robert Cobb/ Don Cartwright/ Jonathan Morphew	S

5. Promote efficient energy utilization and environmentally responsible operations

	Primary Responsibility	Time Focus
1. Provide for implementation and continuing development of Delta's Conservation and Efficiency Program as set out in Delta's tariffs with regard to demand side management	Jeff Steele/ Matt Wesolosky	S
2. Monitor carbon emissions restrictions and EPA requirements that develop and maintain compliance with regulations and requirements	Johnny Caudill/ Jonathan Morphew/ Don Cartwright	L
3. Promote by appropriate means the environmental benefits and advantages of the utilization of natural gas	Johnny Caudill/ Jeff Steele	S
4. As compressed natural gas stations are developed on Delta's system, promote the efficiency, social and environmental benefits of natural gas as a vehicular fuel	Jeff Steele	L

6. Pursue safety for employees, customers and the communities Delta serves

	Primary Responsibility	Time Focus
1. Continue appropriate safety training and incentives that emphasize safety to employees and customers, and continue to promote a safe environment at all company facilities	Johnny Caudill/ Mary Rupard	S
2. Promote safety for customers through meetings, bill inserts and other media efforts to provide safety information to customers and communities served by Delta	Johnny Caudill/ Mary Rupard/ Emily Bennett	S
3. Appropriately respond to security threats; respond to requests and requirements from appropriate federal and state agencies as necessary	Johnny Caudill/ Don Cartwright	S
4. Ensure the operations and maintenance of Delta's facilities in a safe and efficient manner	Johnny Caudill/ Don Cartwright	L
5. Promote public safety in communities served by Delta by reviewing natural gas safety issues and Delta's safety efforts at meetings that include emergency officials, first responders, governmental agencies, excavators, community leaders, customers and others	Johnny Caudill/ Mary Rupard	S
6. Continue public awareness safety mailings within Delta's service area to Delta's customers and to the communities Delta serves	Johnny Caudill/ Mary Rupard	L
7. Continue Delta's Pipe Replacement Program and increase quantities of pipe replaced	Johnny Caudill/ Rob Miller/ Matt Wesolosky	S

7. Promote, maintain and improve the competitive advantages of the Company's products and services

		Primary Responsibility	Time Focus
1.	Provide market responsive rates and services to enhance Delta's ability to compete; pursue rates that will be competitive with other energy sources (especially electric) in Delta's service area	All Officers/ Jenny Croft	L
2.	Develop and utilize marketing strategies and plans to provide for Delta to effectively compete for existing and new markets	Johnny Caudill/ Jeff Steele	S
3.	Promote customer retention through appropriate means such as emphasis on the quality of products and services	Johnny Caudill/ Jeff Steele	L
4.	Maintain and pursue the improvement of efficiencies in all aspects of Delta's operations and reduce or contain costs where feasible to maintain competitiveness	All Officers	S
5.	Utilize performance metrix for internal trend analyses and external comparisons to provide information to assist in improving the Company's efficiency and productivity	All Officers	L

8. Conduct all business efforts, operations and financial reporting in an ethical and appropriately risk controlled manner and in compliance with applicable statutory, environmental and regulatory requirements

		Primary Responsibility	Time Focus
1.	Ensure compliance with Delta's Code of Conduct and Ethics	Glenn Jennings/ John Brown	L
2.	Maintain an effective system of internal control that provides adequately for Delta's needs	Glenn Jennings/ John Brown/ Matt Wesolosky/ Jenny Croft/ Casey Mudd	L
3.	Update the risk assessment review annually and discuss with the Board of Directors	Glenn Jennings/ John Brown	S
4.	Evaluate insurance coverage annually and maintain appropriate protection on Company assets/functions; obtain periodic outside evaluation of risks, coverage and costs	John Brown/ Denisa King	S
5.	Update Delta's cost allocation manual, file it with the Kentucky Public Service Commission and operate in accordance with it	John Brown/ Matt Wesolosky/ Casey Mudd	S
6.	Maintain Delta's existing strong, positive reputation in the state and the gas industry	All Officers	L
7.	Continue to monitor and mitigate cyber security risks	John Brown/ Matt Wesolosky/ David Turpin	L
8.	Maintain adequate recovery plans for IT in the event of cyber security problems/interruptions	John Brown/ Matt Wesolosky/ David Turpin	L