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July 14, 2017

Executive Director Earl Taylor
c/o Sharla Dillon
Tennessee Public Utility Commission
502 Deaderick Street
Nashville, TN 37243

Re: Docket No. 16-00098, Prudency Review of Gas Purchase

Dear Mr. Taylor:

On behalf of Chattanooga Gas Company (the "Company" or "CGC"), enclosed please find for filing with the Tennessee Public Utility Commission ("TPUC") an original and four (4) copies of the public redacted version of the report on the Review of Performance Based Ratemaking Mechanism Transactions and Activities, dated June 2017 which has been prepared by Exeter Associates, Inc. ("Exeter") in compliance with the TPUC Order dated October 13, 2009, in Docket No. 07-00224, and as the Audit of Prudence of Gas Purchases, pursuant to the Tenn. Comp. R. & Regs. 1220-04-07-.05 and the TPUC Order dated May 25, 2017, in Docket No. 16-00098 (the "Report"). Also included with this letter is a confidential version of the Report, submitted under seal.

With respect to the findings of fact and areas of concern presented on pages 51-54 of the Report, the Company has chosen only to address the conclusion and recommendation on page 54 regarding mutual aid. CGC believes that the recommendation to use "economic value" as the compensation mechanism is not in the best interests of ratepayers. CGC offers the following information as explanation and justification for the actions it took in connection with the LNG transfers in the first half of 2014 and why the neutral, in-kind exchange approach used by the Company is in the public interest.

Mutual aid exchanges exist throughout the utility industry, including local distribution companies ("LDCs"), to provide aid or assistance to address or prevent service interruptions. The large number of floods, hurricanes, tornados, severe cold, and other weather impacting events that have caused widespread service interruptions or potential disruptions in service has led the utility industry to formalize and expand mutual aid exchanges to better ensure the safe, efficient, and timely restoration of service or prevention of service outages. In providing assistance to requesting utilities, profit is not the motivation.

In this instance the liquefied natural gas ("LNG") was transferred from CGC's LNG facility to the LNG facility of CGC's affiliate, Atlanta Gas Light ("AGLC"), in order to address a situation that threatened AGLC's ability to continue to provide service to its residential and its other firm customers. The transfer and repayment in-kind did not result in any change in the cost of gas recovered or to be recovered from CGC's customers. CGC's customers were not negatively impacted by the AGLC LNG transfers. The in-kind exchange was done on a therm for therm basis and not a cost of gas basis. After the transfer back, the Company and its customers were in exactly the same position as before the transfers.

As Exeter correctly points out, when the gas was transferred back to CGC, the market price of the gas was lower than when the gas was transferred to AGLC. While in this particular situation there may have been a revenue benefit to CGC if measured by the price of gas, what if the situation had been reversed and the price of gas was higher when returned to CGC? The inherent problem with Exeter's recommendation is that if in these types of mutual aid gas exchanges, if the transactions are measured by market price and not simply as in-kind exchanges, then the utility's customers are going to be a risk for a gain or increase in cost by providing mutual assistance. It seems unlikely that if the market prices had been reversed that Exeter would now be recommending that CGC's customers should have been billed an additional $114,300. Further, a market price approach could inhibit future mutual assistance if the providing utility is at risk of receiving back higher priced gas, with the loss of such mutual aid adversely impacting the customers of the utility with the outage or potential service disruption. Only by accounting for mutual aid gas transfers of gas as in-kind exchanges, as CGC did in this situation, will ratepayers of both the providing LDC and the receiving LDC be held harmless while obtaining the necessary gas.

In accepting the Report, the TPUC should find that the 2014 in-kind exchanges were appropriate and the TPUC should not take any further action with respect to those transfers since customers were not adversely impacted by the exchanges. Furthermore, the TPUC should not adopt the Report's recommendation that further exchanges be done on an economic basis.

Should you have any questions concerning this matter, please do not hesitate to contact me.

Sincerely,

J. W. Luna

JWL/cb
Enclosures
cc: Vance Broemel, Esq.

PUBLIC-REDACTED COPY
Final Report

REVIEW OF PERFORMANCE BASED RATEMAKING MECHANISM TRANSACTIONS AND ACTIVITIES

Prepared for:

AUDIT STAFF OF THE TENNESSEE REGULATORY AUTHORITY

CONSUMER ADVOCATE AND PROTECTION DIVISION OF THE TENNESSEE ATTORNEY GENERAL

JUNE 2017

Prepared by:

EXETER ASSOCIATES, INC.
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION AND SCOPE OF INVESTIGATION

On October 13, 2009, the Tennessee Regulatory Authority (TRA or Commission) issued an Order in Docket No. 07-00224 requiring a comprehensive triennial review (or audit) of the transactions and activities related to the Performance Based Ratemaking Mechanism (PBRM) of Chattanooga Gas Company (CGC or Company) for the period April 2010 through March 2013. This review was to be conducted by an independent consultant. Following a required RFP selection process, Exeter Associates, Inc. (Exeter) was selected as the independent consultant to perform this triennial review. In June 2014, Exeter submitted a report presenting the results of its review of CGC's PBRM for the period April 2010 through March 2013.

In an Order issued in Docket No. 07-00224 on December 29, 2014, the TRA voted to extend the PBRM triennial review process for the period April 2013 through March 2016. Exeter was again selected through an RFP process to perform this review. Exeter has also previously been selected to perform similar audits of the performance incentive programs of the Piedmont Natural Gas Company and Atmos Energy Corporation.

Under its PBRM, the CGC's commodity gas costs are compared to a benchmark amount. If CGC's total commodity cost of gas for a Plan Year (12 months ended June) does not exceed the benchmark amount by one percentage point for that Plan Year, CGC's gas costs will be deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05(1)(a) is waived. On August 26, 2016, CGC submitted its annual PBRM filing for the 12-month period ended June 30, 2016. That filing indicated that CGC's commodity costs exceeded the benchmark amount by 3.3 percent. As a result, a prudency review of CGC's purchased gas costs is required. On October 10, 2016, CGC filed a motion with the Commission for a waiver of TRA Administrative Rule 1220-4-7-.05(1)(a) to expand the scope of the previously ordered April 2013 through March 2016 triennial review to include the review of CGC's PBRM through June 2016, and to address the prudence of CGC's gas costs for the period July 2015 through June 2016. Audit Staff of the TRA (TRA Staff) and the Consumer Advocate Protection Division (CAPD) of the Tennessee Attorney General each supported CGC's motion, and the motion was approved in an Order issued on January 31, 2017 in Docket No. 16-00098.

The scope of this audit is to review and evaluate the reasonableness of CGC's and its affiliates' gas procurement transactions and activities for the period April 2013 through June 2016 (audit or review period). This audit includes review of: (1) CGC's actual gas procurement transactions and costs, including storage activity, as reported in the Company's Actual Gas Adjustment (AGA) filings, which provide for a reconciliation of CGC's actual gas costs and gas cost recoveries; (2) CGC's annual PBRM filings, which compare CGC's actual commodity gas costs with benchmark amounts to evaluate the Company's performance under the PBRM; and (3) CGC's Interruptible Margin Credit Rider (IMCR) filings, which detail the sharing of revenue generated under the Company's Asset Management and Agency Agreements (AMAs) and from the Company's off-system sales activities.

A draft report presenting the findings, results, and conclusions of Exeter's review was provided to the Company, TRA Staff, and the CAPD on June 2, 2017. On June 21, 2017, CGC provided to Exeter its comments on the draft report. CGC's comments were intended to clarify certain facts regarding its PBRM and its transactions and activities as well as to respond to several findings set forth in the draft report. Exeter has incorporated CGC's comments into this final report (Report) and has responded to CGC's comments as Exeter deemed appropriate.

Exeter's Report consists of five sections in addition to this introductory section. Section 2 of the Report identifies the interstate pipeline transmission companies serving CGC, the services the Company purchases from each pipeline, and the Company's review period gas supply arrangements. Included in Section 2 is a description of the Company's AMAs with Sequent Energy Management, L.P. (Sequent), an affiliate of CGC. Section 2 also provides a description of the CGC system and the markets it serves. This section includes statistical data identifying the number of customers served and usage by customer class. Section 3 of the Report summarizes and evaluates CGC's activities and performance under the PBRM. The fourth section of the Report evaluates CGC's storage and liquefied natural gas (LNG) off-system sales activities. Section 5 of the Report evaluates the reasonableness of CGC's capacity portfolio. This includes an evaluation of CGC's design peak day forecasting procedures and examines the balance between CGC's capacity resources and its customers' requirements. The final section of the Report summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement, which may warrant further consideration.

2.0 CHATTANOOGA GAS COMPANY'S SYSTEM AND MARKETS

The Chattanooga Gas Company provides natural gas sales and distribution service to the counties of Hamilton and Bradley, Tennessee, which are referred to as the Chattanooga and Cleveland service territories, respectively. CGC contracted for firm transportation and storage services from three interstate pipelines during the review period: East Tennessee Natural Gas (ETNG), Tennessee Gas Pipeline (TGP), and Southern Natural Gas Company (SONAT). Of these three interstate pipelines, CGC is interconnected to two: ETNG and SONAT. CGC has nine interconnects with ETNG and one interconnect with SONAT. Figure 1 presents a map of the Company's service territory and the interstate pipelines serving CGC. The interstate pipeline services reserved by CGC during the audit period are described in Section 2.1, below. Section 2.1 also discusses Texas Eastern Transmission Corporation, LP (Texas Eastern) and Transcontinental Gas Pipe Line Company, LLC (Transco), two interstate pipelines that affected the benchmarking used under the PBRM. CGC operated under two AMAs with its affiliate, Sequent Energy Management, L.P., during the review period. CGC's AMAs with Sequent are described in Section 2.2 of the Report. CGC's review period gas supply arrangements are described in Section 2.3, and Section 2.4 of the Report summarizes the jurisdictional services provided by CGC, the number of customers served, and annual throughput statistics.

2.1 Interstate Pipeline Transportation Services

CGC's transportation arrangements with ETNG and SONAT provide for the delivery of gas supplies directly to CGC's system (citygate), while TGP provides for the upstream delivery of gas to ETNG. Gas supplies delivered to CGC by ETNG are generally purchased in the Gulf Coast production region and initially delivered to ETNG by TGP. Gas supplies delivered to CGC by SONAT are also generally purchased in the Gulf Coast production region and delivered directly to CGC. Table 1 summarizes the pipeline services purchased by CGC to meet customer demands for the winter of 2015-2016. This information is provided to assist in evaluating CGC's gas procurement transactions and activities and in evaluating CGC's capacity resources.

Figure 1.
CHATTANOOGA GAS COMPANY
System Map

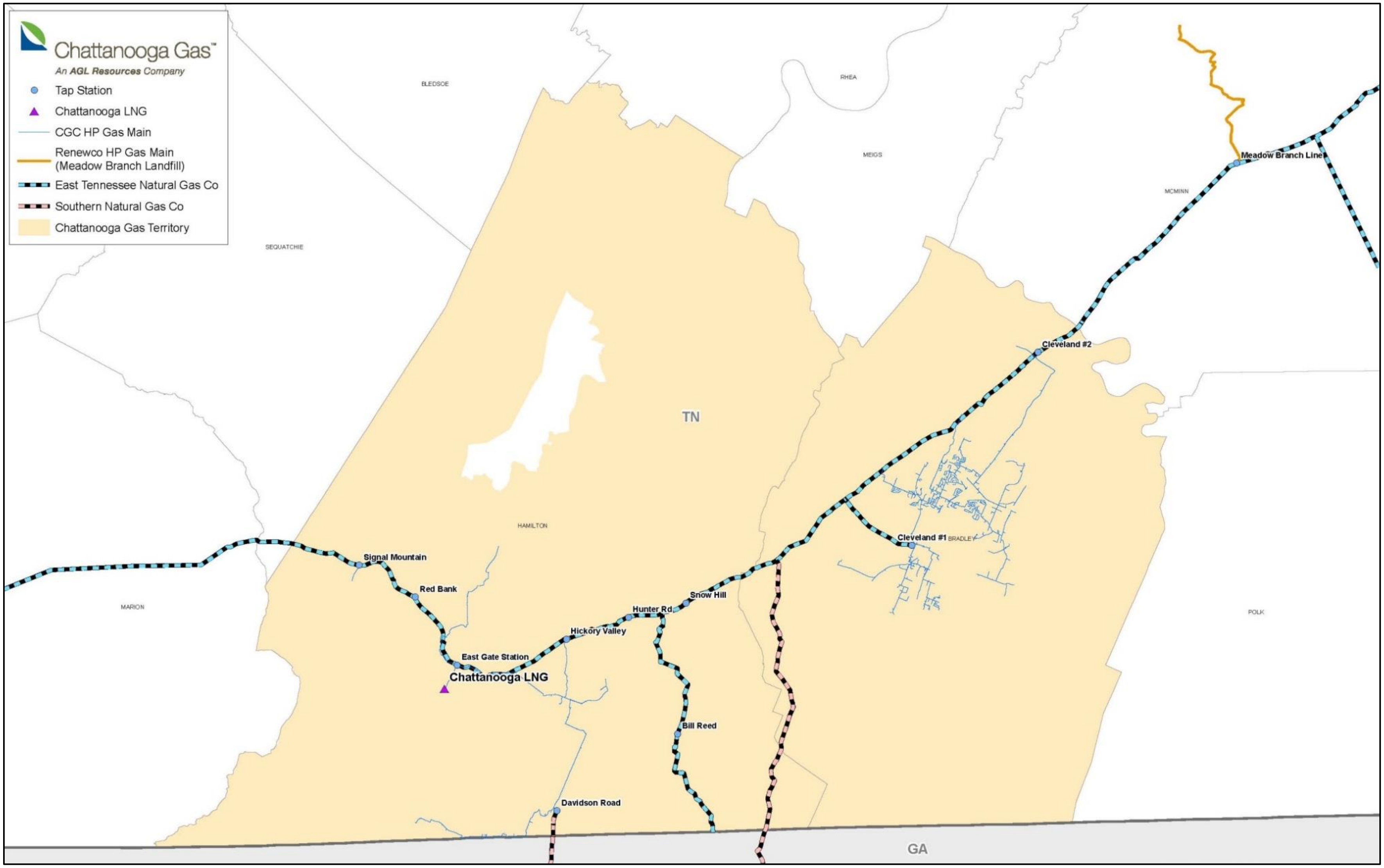


Table 1.
CHATTANOOGA GAS COMPANY
Summary of Design Day Capacity Resources
(2015-2016 Winter Season)

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Winter Season (Dth)	Total Annual Quantity (Dth)	Contract Expiration
UPSTREAM RESOURCES						
TGP						
Firm Transportation (FT-A)	48082	37,819	37,819	5,710,669	13,803,935	10/31/2020
Storage Service (FS-MA)[i]	3947	7,741[i]	0	852,286[i]	0	11/01/2020
Storage Service (FS-PA)[i]	22923	13,659[i]	0	2,042,390[i]	0	10/31/2020
Total Upstream Resources:		**37,819**	**37,819**	**5,710,669**	**13,803,935**	
CITYGATE RESOURCES						
ETNG						
Firm Transportation (FT-A)	410203	13,000	13,000	1,963,000	4,745,000	10/31/2022
Firm Transportation (FT-A)	410204	28,350	28,350	4,280,850	10,347,750	10/31/2018
Subtotal ETNG:		41,350	41,350	6,243,850	15,092,750	
SONAT						
Firm Transportation (FT)	FSNG130	13,221	13,221	1,996,371	4,825,665	08/31/2018
Firm Transportation (FT-NN)	FSNG130	14,346	14,346	2,166,246	5,236,290	08/31/2018
Storage Service (CSS)[ii]	SSNG69	14,346[ii]	0	710,484[ii]	0	08/31/2018
Subtotal SONAT:		27,567	27,567	4,162,617	10,061,955	
CGC LNG	None	90,404	0	1,207,574	1,207,574	None
Total Citygate Resources:		**159,321**	**68,917**	**11,614,041**	**26,362,279**	

Dth = dekatherms; MDQ = maximum daily delivery quantity.
[i] Delivered under TGP FT-A service.
[ii] Delivered under SONAT FT-NN service.

2.1.1 Tennessee Gas Pipeline

The TGP system was initially designed to transport gas from the Texas, Louisiana, and Gulf of Mexico (collectively, Gulf Coast) natural gas production region to markets in the Northeast U.S. In the Gulf Coast production region, the TGP system consists of three primary transmission lines, referred to as the 100, 500, and 800 Legs. The TGP system is also divided into eight zones (Zones 0, L, and 1-6) for rate purposes. The State of Texas is designed as Zone 0, Zone L consists largely of the State of Louisiana, and

Zone 1 extends from the Texas border with Northern Louisiana to the Kentucky/Tennessee border. A map of the TGP system is provided in Figure 2.

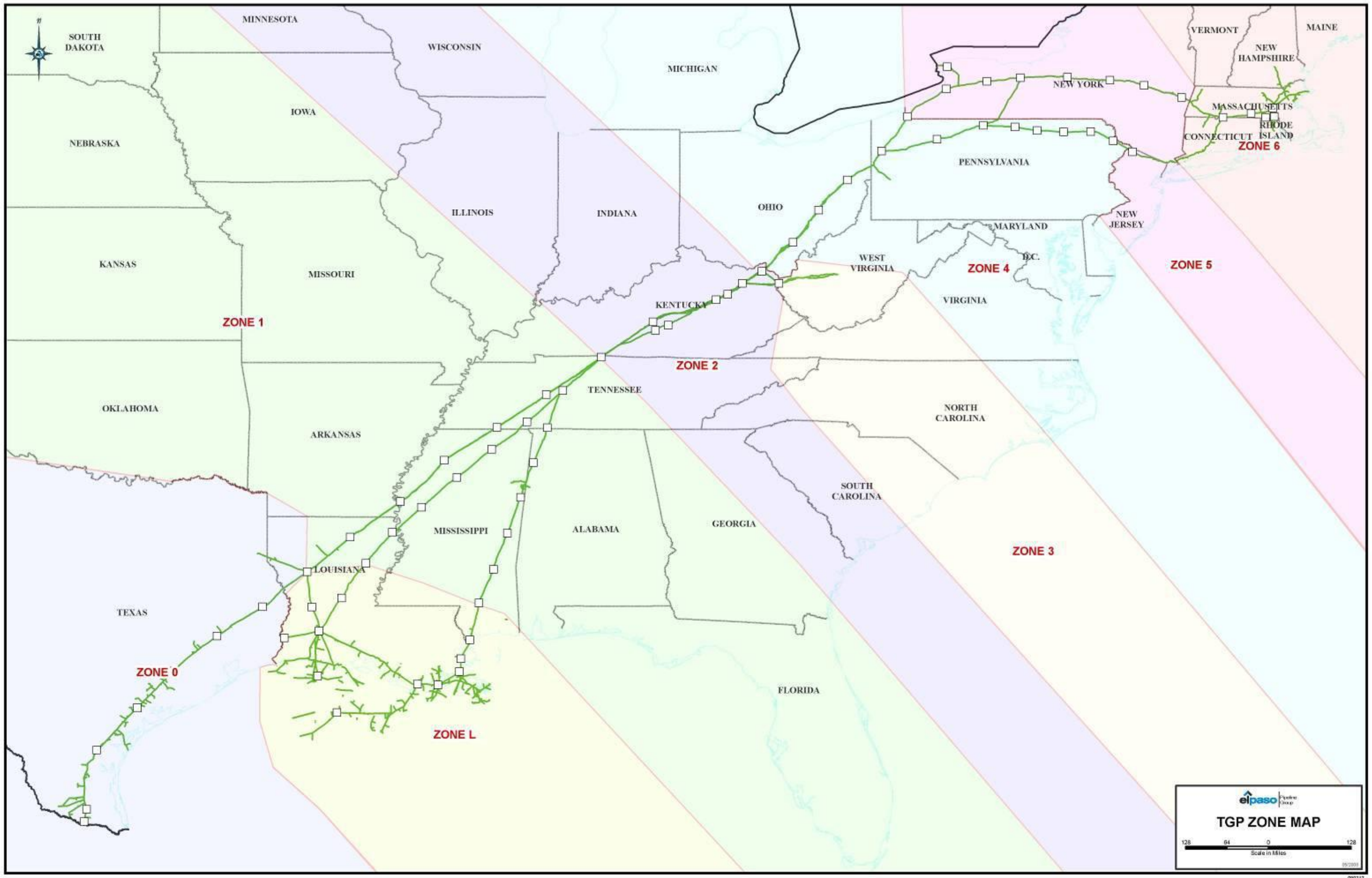
During the review period, CGC held firm transportation service with TGP under Rate Schedule FT-A (Contract No. 48082). This contract provided for the delivery of Gulf Coast supplies directly to ETNG in TGP Zone 1 at two delivery points.[1] Contract No. 48082 has a maximum daily delivery quantity (MDQ) of 37,819 Dth. CGC's primary receipt point capacity under TGP Contract No. 48082 is subdivided by zone and leg as follows:

Tennessee Gas Pipeline Capacity	
Zone – Leg	**MDQ (Dth)**
Zone 0 – 100 Leg	11,090
Zone 1 – 100 Leg	21,139
Zone L – 500 Leg	700
Zone L – 800 Leg	4,890
Total:	**37,819**

CGC also maintained market area firm storage service with TGP under Rate Schedule FS-MA (Contract No. 3947) and production area firm storage service with TGP under Rate Schedule FS-PA (Contract No. 22923). Gas was delivered to and from storage under CGC's FT-A firm transportation arrangement with TGP. FS-MA provided for an MDQ of 7,741 Dth, and a maximum winter season deliverability of 852,286 Dth. FS-PA provided for an MDQ of 13,659 Dth, and a maximum winter season deliverability of 2,042,390 Dth.

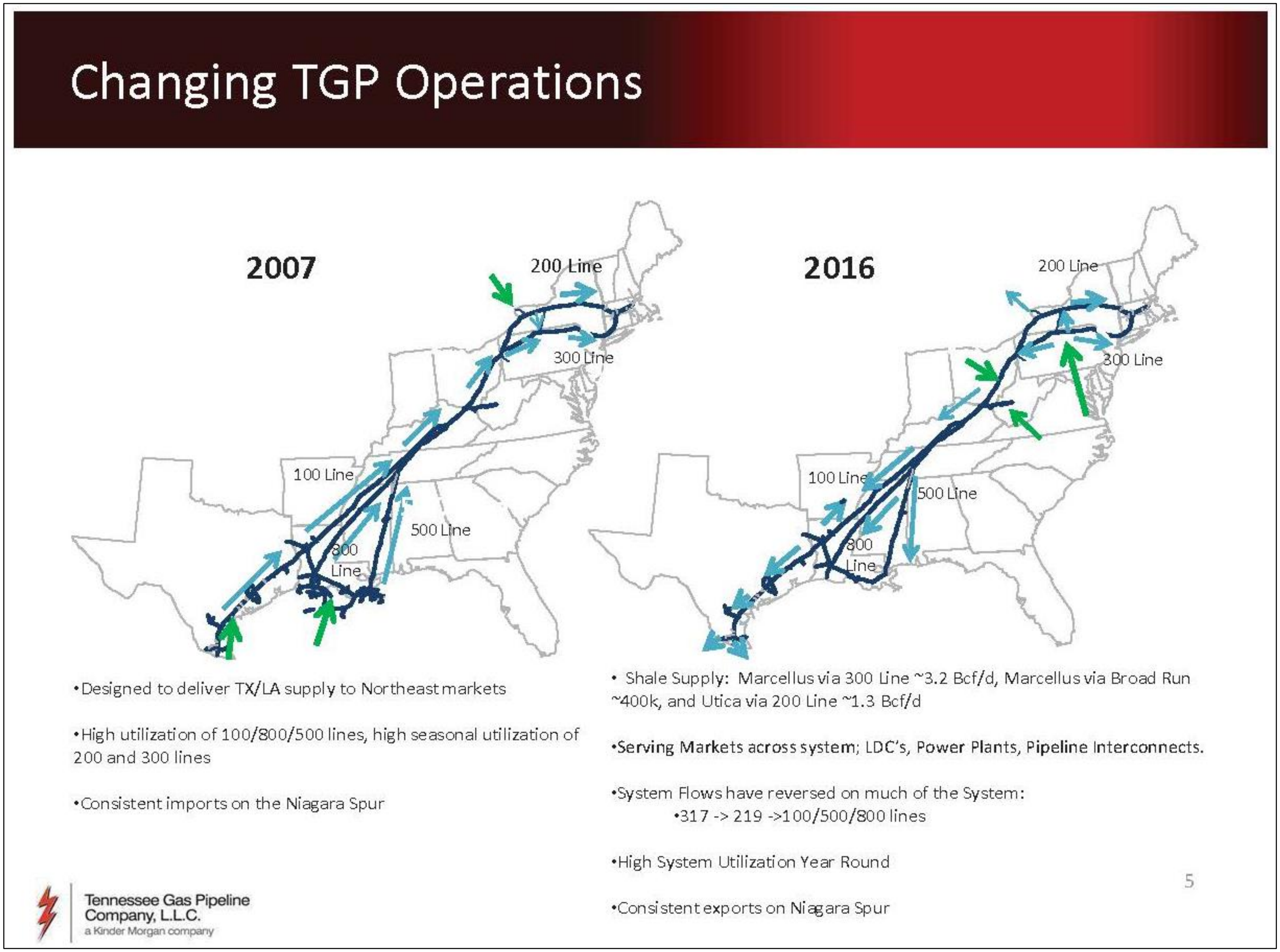
[1] ETNG interconnects with TGP at East Lobelville and Ridgetop, Tennessee.

Figure 2.
TENNESSEE GAS PIPELINE
System Map



The flow of gas supplies on the TGP system has changed dramatically since 2007 as a result of the significant increase in natural gas production in the Marcellus and Utica Shale (collectively, Marcellus) region in Pennsylvania, Ohio, West Virginia, and New York. The Marcellus region is now the most prolific natural gas production region in the U.S. As shown in Figure 3, in 2007, the flow of gas on the TGP system was northerly from the Gulf Coast production region to markets in the Northeast U.S. Today, as also shown in Figure 3, the flow of gas on the TGP system is largely southerly from the Marcellus region to the Gulf Coast production region. As indicated in Table 5 in Section 3.1.3 of the Report, Marcellus Shale (TGP Zone 4, 200 Leg) gas supplies were generally lower-cost than Gulf Coast production area (TGP Zones 0, 1, and L) supplies during the review period. CGC was unable to access Marcellus Shale supplies during the review period because the Company's primary receipt points under its FT-A firm transportation arrangement with TGP were in the Gulf Coast production region. The inability of CGC to access Marcellus Shale supplies was confirmed through a discussion with a representative of TGP.

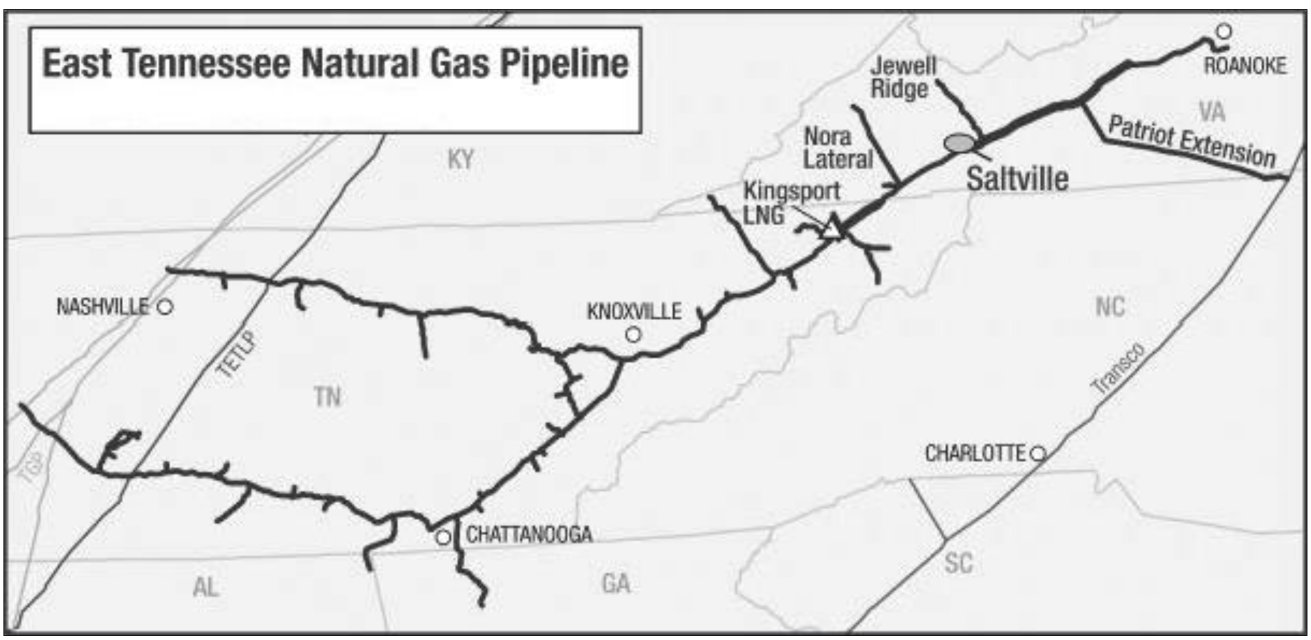
Figure 3.
TENNESSEE GAS PIPELINE
Changing Operations



2.1.2 East Tennessee Natural Gas

ETNG consists of two mainline systems in Central Tennessee that converge near Knoxville and extend to an area just south of Roanoke, Virginia. ETNG provides for the delivery of gas supplies from TGP to CGC. A map of the ETNG system is presented in Figure 4. During the review period, CGC held two firm transportation service arrangements with ETNG under Rate Schedule FT-A (Contract Nos. 410203 and 410204). Contract No. 410203 provided for the delivery of 13,000 Dth per day and Contract No. 410204 provided for the delivery of 28,350 Dth per day. After adjusting for fuel retention, CGC's ETNG capacity was greater than its delivered TGP capacity by approximately 4,899 Dth per day during the review period. The firm receipt point for this 4,899 Dth of capacity was on the Nora Lateral located in Dickenson County in Southwest Virginia. CGC used this capacity to deliver gas purchased on a delivered-to-ETNG basis. CGC also acquired, through a short-term release, 3,000 Dth per day of ETNG capacity for the period October 2013 – April 2014 to address a design day capacity deficiency. This short-term release is discussed further in Section 2.1.4 of the Report.

Figure 4.
EAST TENNESSEE NATURAL GAS
System Map



2.1.3 Southern Natural Gas

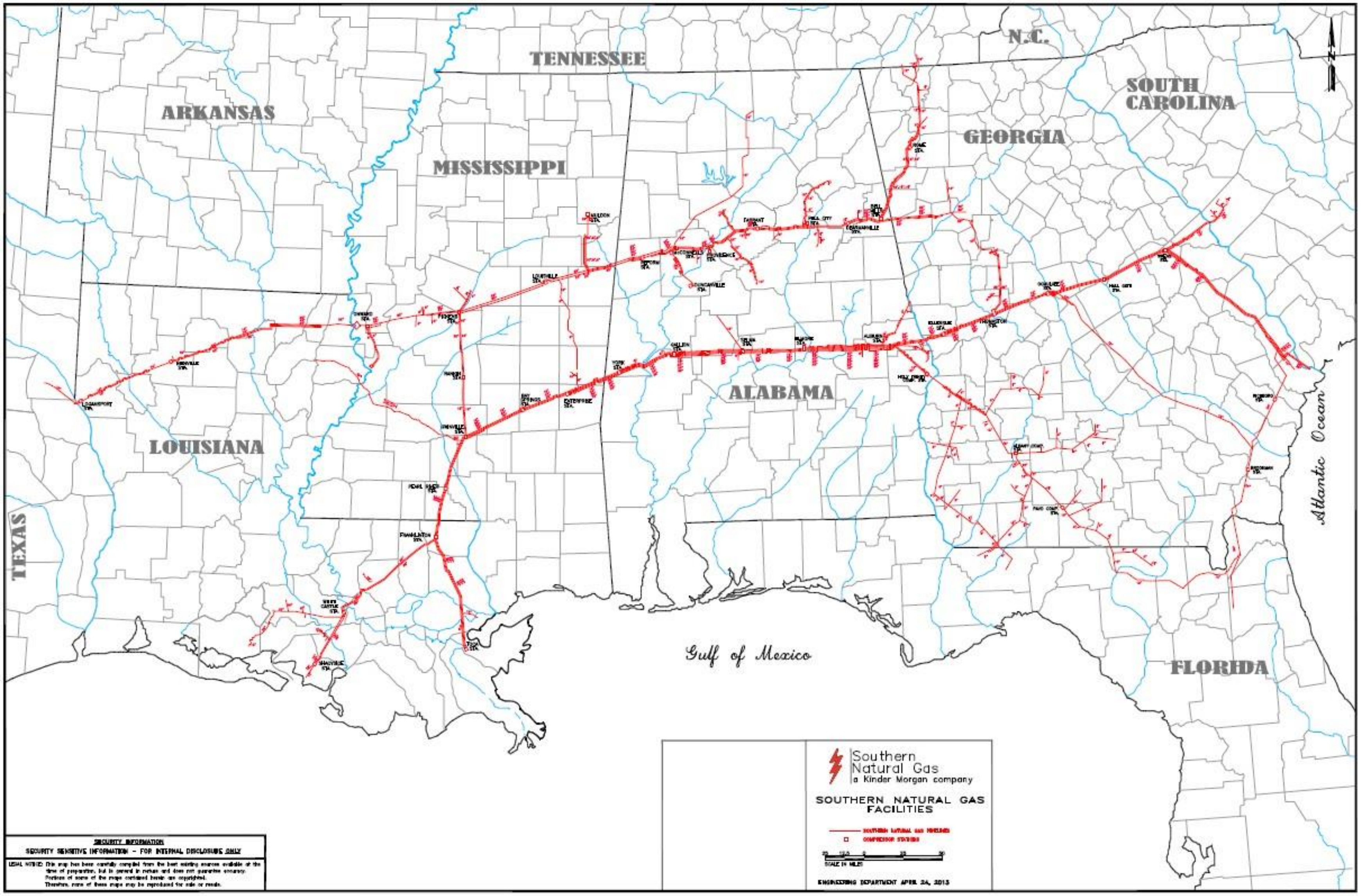
The pipeline facilities of SONAT extend from natural gas supply basins in Texas, Louisiana, Mississippi, Alabama, and the Gulf of Mexico to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SONAT's system consists of four rate zones (0-3), and CGC is located in Zone 3. A map of the SONAT system is presented in Figure 5.

CGC held firm transportation service with SONAT under Rate Schedule FT (Contract No. FSNG130) during the review period. This contract provided for the delivery of 13,221 Dth per day directly to CGC's system.

Under SONAT's standard Rate Schedule FT service, the pipeline is generally only obligated to deliver, and the shipper (e.g., CGC) is entitled to take, the quantity of gas delivered to the pipeline on the shipper's behalf on a daily basis. Shippers provide SONAT notice (through nominations) of the quantity of gas to be delivered each day. Under SONAT's no-notice transportation service arrangements, a shipper is permitted to take daily deliveries of gas, which vary from the nominated quantity. No-notice service is necessary to maintain system reliability for natural gas distribution companies like CGC serving temperature-sensitive usage customers. CGC held a no-notice service with SONAT under Rate Schedule FT-NN during the audit period. Under its FT-NN arrangement, CGC was permitted to take delivery of up to 14,346 Dth per day without notice, subject to the winter season limitation subsequently identified for service under Rate Schedule CSS. CGC was also allowed to use its FT-NN service to take delivery of up to 14,346 Dth per day of nominated supplies.

In conjunction with its FT-NN service, CGC held a firm storage service with SONAT under Rate Schedule CSS (Contract No. SSNG69). This service provided for an MDQ of 14,346 Dth, and was used to support no-notice deliveries under CGC's SONAT FT-NN service arrangement. The maximum winter season delivery quantity under Rate Schedule CSS was 710,484 Dth.

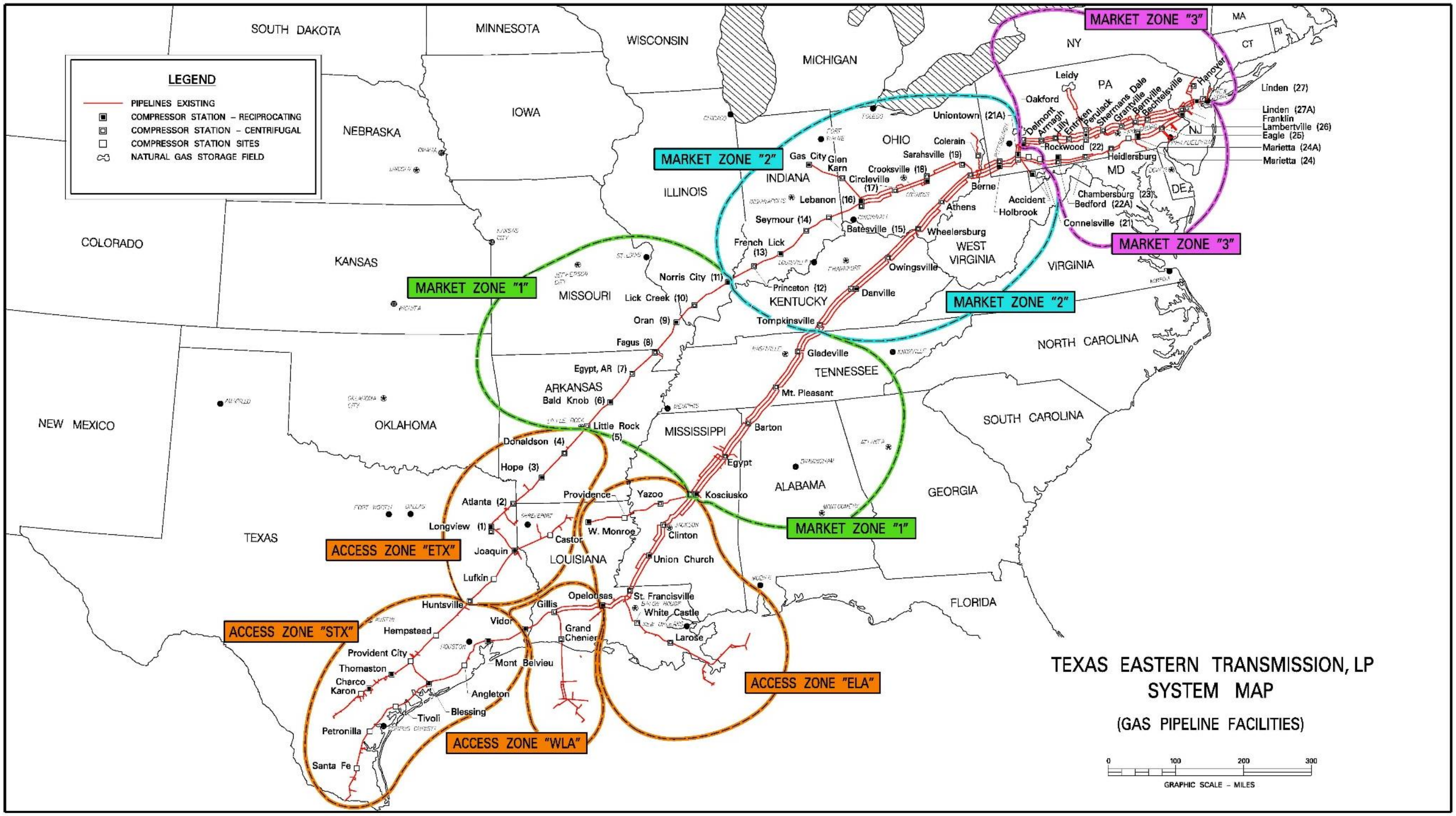
Figure 5.
SOUTHERN NATURAL GAS
System Map



2.1.4 Texas Eastern Transmission, LP

The Texas Eastern system consists of pipeline facilities that extend from the Gulf Coast production region to markets in the Northeast U.S. The Texas Eastern system consists of four Gulf Coast production area access rate zones and three market area rate zones. These zones are identified in Figure 6. Texas Eastern has an interconnect with ETNG at its Mt. Pleasant, Tennessee compressor station in Texas Eastern Market Zone 1 (Zone M-1). Due to the significant increase in production from the Marcellus region, the historical northerly gas flows from the Gulf Coast production region to the Northeast U.S. have changed, and flows on Texas Eastern are now bi-directional. During the winter of 2013-2014, CGC purchased gas at the Texas Eastern/ETNG Mt. Pleasant interconnect. These purchases were delivered to CGC utilizing the 3,000 Dth per day of ETNG capacity that CGC acquired through a short-term release.

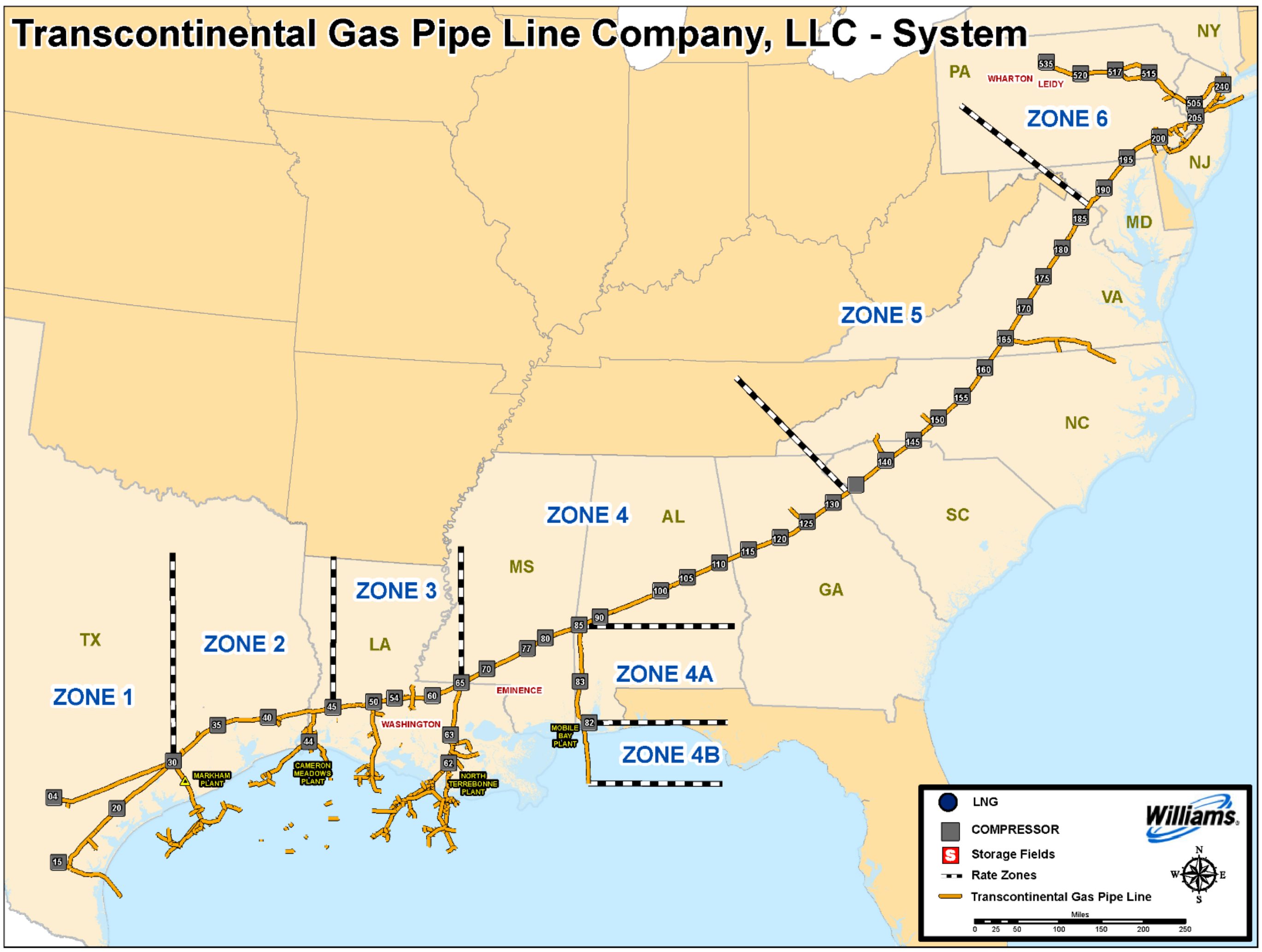
Figure 6.
TEXAS EASTERN TRANSMISSION, LP
System Map



2.1.5 Transcontinental Gas Pipe Line Company, LLC

Transco also consists of pipeline facilities that extend from the Gulf Coast production region to markets in the Northeast U.S. The Transco system consists of six rate zones. These zones are identified in Figure 7. Transco interconnects with ETNG in Transco Zone 5 near Cascade Creek, North Carolina (see Figure 4). CGC purchased gas priced based on Transco Zone 5 index prices during the review period. Index prices are discussed further in Section 3.1.1 of the Report.

Figure 7.
TRANSCONTINENTAL GAS PIPE LINE COMPANY, LLC
System Map



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2.1.6 Liquefied Natural Gas

CGC operates an on-system LNG facility. In 2014, CGC made distribution system enhancements that increased the daily deliverability of its LNG facility from 78,500 Dth to 90,400 Dth. The LNG facility has a storage capacity of 1,207,574 Dth, and can produce at maximum daily deliverability for approximately 13 days.

2.2 Asset Management and Agency Agreements

CGC operated under two AMAs with Sequent during the review period. The first AMA was initially in effect for the three-year period April 1, 2011 through March 31, 2014 (2011 AMA). The term of the 2011 AMA was subsequently extended, with TRA approval, for an additional year. The term of the second AMA is April 1, 2015 through March 31, 2018 (2015 AMA). Under each AMA, CGC's pipeline firm transportation and contract storage capacity assets were managed under an agency agreement by Sequent. The AMAs also provided that CGC would purchase the gas supplies delivered under the managed assets from Sequent. CGC maintained control of its LNG facilities under the AMAs.

Under the AMAs, CGC determined how its pipeline transportation and storage assets should be used on a daily basis to meet its customers' requirements (referred to as "logical dispatch"). On a daily basis, Sequent was entitled to use CGC's assets in the manner determined by CGC, use CGC's assets in a different manner, or use other assets to which it had access as long as Sequent satisfied CGC's requirements. The billing arrangements under the AMAs provided that CGC would be responsible for all charges related to the use of CGC's assets regardless of whether those charges reflected CGC's logical dispatch decisions or Sequent's activities, and Sequent would reimburse CGC for the costs that were not incurred consistent with CGC's logical dispatch instructions. Exeter's audit reviewed a sampling of the detailed workpapers supporting the separation of costs between CGC and Sequent, and our review revealed no concerns.

The TRA initially approved the 2011 AMA and its subsequent one-year extension in Docket No. 10-00049. [redacted]

[redacted]

The TRA approved the 2015 AMA in Docket No. 14-00137. [redacted]

2.3 Gas Supply Arrangements

Under the AMAs, CGC was required to purchase from Sequent all of its gas supplies delivered under the transportation arrangements assigned to Sequent. Sequent could offer, but was not required to provide, CGC gas supplies delivered under other transportation arrangements. With limited exceptions, all of CGC's review period gas supplies were purchased through Sequent, either under the AMAs or under arrangements outside the AMAs. The AMA purchases from Sequent were generally made [redacted]. The exceptions to CGC's purchases from Sequent under the AMAs and purchases from Sequent under arrangements outside the AMAs are subsequently discussed. Exeter's audit did not find CGC's gas purchase arrangements under or outside the AMA to be unreasonable.

2.3.1 [redacted] Citygate Peaking Service

During the review period CGC entered into an arrangement with [redacted] for a firm delivered-to-citygate gas supply peaking service for the period December 1, 2013 through February 28, 2014. This arrangement was made to address an incremental supply need to meet design day requirements for the winter of 2013-2014, and provided up to 5,000 Dth/day for 15 days. [redacted]

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2 [redacted]

[redacted] No gas supplies were purchased by CGC under the arrangement with Twin Eagle.

2.3.2 [redacted] – Peaking Services

CGC issued RFPs for firm citygate peaking supply services for the winters of 2013-2014 and 2014-2015. [redacted] No gas supplies were purchased by CGC under either arrangement. As discussed in the following section, CGC purchased spot market gas from Sequent during the winter of 2014-2015 on 13 days. Spot market purchases are those for which there were no existing contractual pricing arrangement and no obligation for the seller to provide supplies.

2.3.3 Nora Lateral Purchases

CGC purchased baseload gas supply under a contract with [redacted] to fill its open 4,899 Dth per day of ETNG Nora Lateral capacity during the winter of 2013-2014 (see Section 2.1.2). Gas supplies purchased under this contract were priced [redacted] The contract was a three-year agreement that expired at the conclusion of the 2013-2014 winter season. This contract was reviewed by Exeter in the prior triennial audit.

For the winter of 2014-2015, CGC issued an RFP for firm gas supplies to fill its open ETNG Nora Lateral capacity [redacted]

[redacted]

[redacted] Since no index price is published specifically for the NORA Lateral location, the commodity pricing provisions under this contract were based on [redacted]. CGC also subsequently negotiated and entered into a contract with [redacted].

2.3.4 [redacted] – Mt. Pleasant

As initially explained in Section 2.1.2, CGC acquired 3,000 Dth of ETNG capacity for the period October 2013 – April 2014 under a short-term release to address a design day capacity deficiency. The receipt point for the ETNG capacity acquired by CGC under the release was ETNG's interconnect with Texas Eastern in Mt. Pleasant, Tennessee. To fill this capacity, CGC entered into a gas supply arrangement with [redacted] for 5,000 Dth per day that was awarded through an RFP process. [redacted].

2.4 Markets Served by CGC

CGC provided firm bundled utility sales service during the review period, and also provided transportation service from its citygates to a customer's premises for those customers who acquire their own gas supplies on the interstate markets and separately arrange for the delivery of those supplies to CGC's citygates. Table 2 summarizes the number of CGC customers served and annual throughput by rate schedule for the review period.

CGC provides sales service to residential customers under Rate Schedule R-1 – Residential General Service. Sales service under Rate Schedule R-4 – Multi-Family Housing Service was closed as of July 31, 2006, and was only available to a public housing authority or private company operating a housing project. Small Commercial and Industrial General Service is available under Rate Schedule C-1 to sales customers using less than 400 Dth per year. Medium Commercial and Industrial Service is available under Rate Schedule C-2 to sales customers using more than 400 Dth per year. Commercial and Industrial Large Volume Firm Sales Service under Rate Schedule F-1 is available to customers using a minimum of 36,500 Dth per year. Commercial and Industrial Interruptible Sales Service under Rate Schedule I-1 is available to customers using a minimum of 36,500 Dth per year. Interruptible Transportation Service under Rate Schedule T-1 is available to customers using a minimum of 36,500 Dth per year.

Under Rate Schedule T-1, differences between monthly consumption and deliveries to CGC on the customer's behalf are purchased by CGC or sold to the customer, as applicable, at published index prices. Interruptible Transportation Service with Firm Gas Supply Backup is also available to customers using at least 36,500 Dth per year under Rate Schedule T-2. If a customer under Rate Schedule T-2 consumes more gas during a month than the customer has delivered to the Company, the customer purchases the deficient quantity from the Company under Rate Schedule F-1. Deliveries in excess of monthly consumption are purchased by the Company at published index prices. Low Volume Transport Service is available to customers using more than 400 Dth per year under Rate Schedule T-3. If a customer under Rate Schedule T-3 consumes more gas during a month than the customer has delivered to the Company, the customer purchases the deficient quantity from the Company under Rate Schedule C-2. Deliveries in excess of monthly consumption are purchased by the Company at published index prices.

Table 2.
CHATTANOOGA GAS COMPANY
Annual Customers and Volumes by Class

CUSTOMERS BY RATE SCHEDULE	April-Dec 2013	2014	2015	Jan-June 2016
Residential Sales (R-1)	54,114	54,779	55,363	56,252
Multi-Family Housing Sales (R-4)	2	2	2	2
Small Commercial & Industrial Sales (C-1)	6,540	6,591	6,454	6,582
Medium Commercial & Industrial Sales (C-2)	1,639	1,660	1,842	1,857
Commercial & Industrial Interruptible Sales (I-1)	1	1	1	1
Large Volume Commercial & Industrial				
Sales/Transportation with Standby (F-1/T-2)[i]	25	28	29	28
Sales/Transportation with Standby (F-1/T-2/T-1)[ii]	12	12	13	15
Interruptible Transportation (T-1)	27	25	22	18
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	46	47	47	48
Special Contract	1	1	2	2
Total Customers:	**62,409**	**63,146**	**63,776**	**64,805**

VOLUMES BY RATE SCHEDULE (Dth)	April-Dec 2013	2014	2015	Jan-June 2016
Residential Sales (R-1)	1,799,998	4,013,256	3,562,986	2,254,708
Multi-Family Housing Sales (R-4)	4,273	8,245	8,062	4,734
Small Commercial & Industrial Sales (C-1)	349,639	911,869	700,068	466,327
Medium Commercial & Industrial Sales (C-2)	1,444,225	2,649,107	2,646,125	1,596,680
Commercial & Industrial Interruptible Sales (I-1)	37,698	43,618	45,409	20,960
Large Volume Commercial & Industrial				
Sales/Transportation with Standby (F-1/T-2)[i]	1,031,656	1,839,194	1,975,524	973,063
Sales/Transportation with Standby (F-1/T-2/T-1)[ii]	1,316,647	1,373,815	1,744,666	1,036,223
Interruptible Transportation (T-1)	2,455,518	3,085,626	2,083,227	982,968
Low Volume Commercial & Industrial				
Sales/Transportation with Standby (T-3/C-2)	396,552	621,101	610,889	318,929
Special Contract	1,034,739	1,448,992	1,378,158	757,441
Total Volumes:	**9,870,945**	**15,994,822**	**14,755,114**	**8,412,033**

[i] Full Standby Service.
[ii] Partial Standby Service.

3.0 PERFORMANCE BASED RATEMAKING MECHANISM RESULTS

This section of Exeter's Report summarizes and evaluates CGC's activities and performance under the Performance Based Ratemaking Mechanism. The PBRM is designed to encourage the Company to perform its gas purchasing activities at minimum cost. The PBRM establishes monthly benchmarks to which the Company's gas commodity costs are compared. If CGC's total monthly commodity gas costs for a Plan Year do not exceed the total benchmark amount by one percent, the Company's gas costs will be deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05(1)(a) is waived. As previously indicated, during the Plan Year ended June 30, 2016, the Company's commodity gas costs exceeded the benchmark amount by 3.3 percent, requiring a prudence review of purchased gas costs for that Plan Year. The tariff sheets governing CGC's PBRM are included as Appendix A to the Report. The Company's PBRM tariff also includes Affiliate Transaction Guidelines and RFP Procedures for Selection of an Asset Manager or Gas Provider.

3.1 Commodity Gas Costs

3.1.1 Background

In the natural gas industry, there are primarily two types of gas supply purchase arrangements—monthly baseload purchases and daily purchases. Monthly baseload purchases are generally arranged several days prior to the month of delivery, commence flow on the first day of the month, and provide for the delivery of the same quantity of gas on each day during the month. Daily purchases are generally arranged the day prior to delivery. While daily purchases generally flow for one day, daily purchases may also be arranged for multiple consecutive days.

There are various natural gas industry publications that identify, after the fact, the average price paid for gas supplies at major natural gas trading locations. These average or market prices are referred to as "index prices." First-of-the-month (FOM) index prices are published in *Inside FERC's Gas Market Report (Inside FERC)* and are applicable for monthly baseload purchases. Daily prices are published in *Gas Daily* (GDD) and are applicable for a particular day or weekend/holiday period. Index prices are also included in other natural gas industry publications. Monthly baseload supply can be purchased at a FOM or a GDD price, while daily supply purchases are typically priced at a GDD price. The primary gas trading index locations at which CGC purchases gas are as follows:

Tennessee Gas Pipeline

- Louisiana Zone L – 500 Leg
- Louisiana Zone L – 800 Leg
- Texas Zone 0 – 100 Leg

Southern Natural Gas

- Louisiana

Each of these trading locations is located in the Gulf Coast production region. A summary of CGC's review period FOM priced monthly baseload and GDD priced daily purchases is provided in Table 3. In addition to baseload and daily purchases at these primary locations, CGC purchased supplies at ETNG's Nora Lateral, and at the Texas Eastern/ETNG Mt. Pleasant interconnect in Texas Eastern Zone M-1. All of these purchases were made under firm gas supply arrangements. CGC made spot market purchases delivered into the Nora Lateral sourced at the Transco/ETNG Cascade Creek interconnect in Transco Zone 5, and at the citygate. CGC also made in-ground storage inventory purchases during the review period.

3.1.2 Benchmark Calculation

Under the PBRM, CGC's actual monthly commodity cost of gas is compared to a monthly benchmark cost. Actual and benchmark costs are separately determined for each purchase made by CGC during a month, and actual and benchmark costs are separately summed to evaluate CGC performance under the PBRM.

For FOM baseload purchases made by CGC, the *Inside FERC* index price for each transaction location is applied to the actual quantity of gas purchased by CGC at each location to determine the applicable benchmark cost. For daily purchases, the *Gas Daily* index price for each transaction location is applied to the actual quantity of gas purchased by CGC at that location to determine the applicable benchmark cost. If CGC makes a baseload purchase that is priced on a daily basis at the *Gas Daily* index price, these purchases would be benchmarked based on *Gas Daily* index prices.

Table 3.
CHATTANOOGA GAS Company
Summary of Monthly Baseload and Daily Purchases
(Dth)

	TENNESSEE GAS PIPELINE ZONE O				TENNESSEE GAS PIPELINE ZL 100/500 Leg				TENNESSEE GAS PIPELINE ZL 800 Leg				SOUTHERN NATURAL				NORA LATERAL		OTHER PURCHASES	
	MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY		DAILY		MONTHLY[i]		DAILY[ii]	
	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price	Quantity	Price
Apr 2013	19,770	$3.90	3,225	$4.10	0	$3.98	0	$0.00	0	$3.95	424,976	$4.10	0	$3.98	24,346	$4.01	0	$4.05	0	$0.00
May	12,710	4.10	0	0.00	0	4.26	0	0.00	0	4.13	273,128	4.01	0	4.16	0	0.00	0	4.33	0	0.00
Jun	12,300	4.07	4,833	3.72	0	4.17	0	0.00	0	4.12	188,552	3.80	0	4.17	0	0.00	0	4.24	0	0.00
Jul	0	3.61	3,938	3.57	0	3.71	0	0.00	0	3.67	212,224	3.61	0	3.71	9,327	3.66	0	3.78	0	0.00
Aug	0	3.36	5,549	3.32	0	3.42	0	0.00	0	3.41	343,920	3.40	0	3.42	18,743	3.40	0	3.48	0	0.00
Sep	327,300	3.46	3,043	3.53	0	3.52	0	0.00	0	3.51	420,971	3.57	0	3.54	13,025	3.59	0	3.58	0	0.00
Oct	349,618	3.41	0	0.00	0	3.46	0	0.00	18,104	3.45	303,839	3.66	0	3.47	27,798	3.65	0	3.52	0	0.00
Nov	115,470	3.41	19,213	3.78	0	3.47	67,124	3.69	0	3.45	242,215	3.71	0	3.49	126,639	3.76	150,300	3.56	0	0.00
Dec	193,626	3.68	122,516	4.17	0	3.76	140,303	4.21	0	3.73	20,212	4.29	0	3.78	128,066	4.34	155,310	3.88	0	0.00
Jan 2014	226,889	$4.26	120,026	$4.47	0	$4.36	119,015	$4.76	0	$4.35	51,838	$4.29	0	$4.37	348,325	$4.65	155,310	$4.47	58,102	$5.02
Feb	114,072	5.26	160,094	5.54	0	5.57	32,531	6.75	0	5.49	158,405	5.72	0	5.55	301,911	5.81	140,280	5.62	36,696	6.54
Mar	88,660	4.65	192,995	4.59	0	4.82	73,679	4.42	0	4.79	184,450	5.32	161,603	4.80	58,015	5.21	155,310	4.91	6,116	4.78
Apr	342,210	4.45	0	0.00	0	4.55	0	0.00	135,780	4.52	113,988	4.45	0	4.56	200,116	4.64	0	4.62	3,082	4.47
May	349,680	4.65	0	0.00	0	4.75	0	0.00	73,067	4.72	57,750	4.48	0	4.77	277,473	4.50	0	4.83	0	0.00
Jun	338,370	4.45	0	0.00	0	4.57	0	0.00	16,770	4.54	0	0.00	0	4.58	303,462	4.56	0	4.64	0	0.00
Jul	332,568	4.28	13,224	3.87	0	4.38	0	0.00	0	4.34	0	0.00	0	4.38	302,890	4.04	0	4.45	0	0.00
Aug	238,421	3.68	48,252	3.80	0	3.77	0	0.00	0	3.73	0	0.00	0	3.78	228,028	3.87	0	3.83	0	0.00
Sep	209,640	3.85	70,586	3.80	0	3.92	0	0.00	0	3.91	22,720	3.86	0	3.94	94,069	3.90	0	3.98	0	0.00
Oct	277,481	3.86	65,156	3.63	0	3.93	0	0.00	0	3.93	154,671	3.64	0	3.96	15,330	3.73	0	3.99	0	0.00
Nov	322,380	3.57	12,768	3.95	0	3.67	79,690	4.0449	0	3.64	104,953	4.18	0	3.69	264,894	4.20	0	3.73	0	0.00
Dec	331,793	4.15	14,712	3.21	0	4.25	0	0.00	0	4.22	194,809	3.24	0	4.28	246,009	3.29	0	4.32	6,510	3.28
Jan 2015	349,711	$3.05	0	$0.00	0	$3.17	0	$0.00	55,242	$3.12	106,914	$2.93	0	$3.17	354,615	$2.97	0	$0.00	16,000	$8.93
Feb	201,152	2.73	114,688	2.69	0	2.85	0	0.00	0	2.80	189,840	2.78	0	2.86	472,435	2.85	0	0.00	74,162	13.46
Mar	169,167	2.76	80,805	2.71	0	2.89	0	0.00	0	2.85	114,808	2.93	0	2.88	289,221	2.77	0	0.00	24,495	7.01
Apr	330,090	2.46	87	2.39	0	2.54	0	0.00	119,700	2.52	54,706	2.56	0	2.59	354,223	2.55	0	0.00	0	0.00
May	343,232	2.41	108	2.79	0	2.49	0	0.00	88,133	2.45	19,463	2.83	0	2.49	183,710	2.78	0	0.00	0	0.00
June	322,179	2.72	10,179	2.65	0	2.79	0	0.00	0	2.76	104,269	2.70	0	2.79	14,364	2.75	0	0.00	0	0.00
July	0	2.68	42,953	2.73	0	2.75	0	0.00	0	2.72	65,056	2.81	0	2.76	246,027	2.84	0	0.00	0	0.00
Aug	178,963	2.80	0	0.00	0	2.86	0	0.00	20,212	2.84	46,542	2.72	0	2.86	303,876	2.79	0	0.00	0	0.00
Sep	291,420	2.54	35,803	2.57	0	2.60	47,135	2.62	0	2.58	28,349	2.60	0	2.61	13,858	2.62	0	0.00	0	0.00
Oct	230,113	2.46	16,244	2.25	0	2.50	0	0.00	0	2.48	306,721	2.26	0	2.52	69,443	2.19	0	0.00	0	0.00
Nov	187,500	1.94	46,749	1.97	0	1.97	0	0.00	0	1.95	17,246	2.11	34,560	2.00	3,099	2.18	150,300	3.08	0	0.00
Dec	54,243	2.15	23,595	1.72	0	2.15	0	0.00	0	2.15	24,293	1.99	39,464	2.18	4,131	2.08	155,000	3.26	0	0.00
Jan 2016	67,239	$2.30	260,797	$2.19	0	$2.34	0	$0.00	0	$2.34	124,440	$2.24	41,974	$2.36	229,642	$2.27	155,310	$3.42	0	$0.00
Feb	0	2.13	178,592	1.96	0	2.16	0	0.00	0	2.15	80,108	1.98	38,019	2.17	131,266	2.05	145,290	3.23	0	0.00
Mar	0	1.63	57,435	1.53	0	1.66	0	0.00	0	1.64	54,537	1.73	38,037	1.67	32,525	1.72	155,310	2.76	0	0.00
Apr	103,020	1.82	29,970	1.77	0	1.84	22,426	1.81	0	1.83	331,014	1.84	34,770	1.85	6,911	1.87	150,300	2.41	0	0.00
May	0	1.90	16,800	1.77	0	1.92	5,595	1.88	308,202	1.91	202,163	1.84	37,262	1.95	64,201	1.87	155,310	2.50	0	0.00
Jun	0	1.86	2,240	2.08	0	1.89	0	0.00	221,610	1.88	2,537	2.11	23,400	1.91	13,037	2.63	0	4.05	0	0.00

[i] Reflects monthly baseload purchases priced using NYMEX settlement prices plus a commodity adder.

[iii] Reflects Texas Eastern Zone M-1 firm purchases during the winter of 2013-2014, spot market purchases at ETNG's Nora Lateral, spot market purchases sourced at the Transco/ETNG interconnect in Transco Zone 5, and citygate spot market purchases during the winter of 2014-2015.

The PBRM provides for the benchmarking of long-term purchases (i.e., arrangements with a term of more than one month) based on FOM index prices and a three-year average of premiums paid to suppliers to ensure that long-term supplies are available during peak periods. Although long-term purchases were made during the review period to fill the Company's open ETNG Nora Lateral capacity during the winter of 2013-2014, the winter of 2015-2016, and the summer of 2016, CGC did not use this provision of the PBRM to benchmark these purchases.

In addition to purchases made at its primary trading locations, CGC purchased gas at the Texas Eastern/ETNG Mt. Pleasant interconnect and at the Transco/ETNG Cascade Creek interconnect. Texas Eastern Zone M-1 index prices are applicable for the Mt. Pleasant interconnect purchases and Transco Zone 5 index prices were applicable for purchases at the Cascade Creek interconnect during the review period. CGC also purchased gas delivered into ETNG's Nora Lateral and gas at its citygate for which index prices are not published. For benchmarking these purchases, CGC used what it considered to be the most applicable index price by location and type of purchase (monthly baseload or daily), adjusted for the avoided variable transportation changes that would have been paid for the delivery of that gas to the Nora Lateral or CGC's citygate, respectively. Similarly, for in-ground storage inventory purchases, the most applicable index price is adjusted for benchmarking purposes for the avoided variable transportation and storage injection charges that would have been paid for the delivery of that gas into storage.

For the winter of 2013-2014, the Nora Lateral purchases were benchmarked by CGC based on Tennessee Zone L – 500 Leg index prices, adjusted for the applicable variable transportation charges. After the conclusion of the winter of 2013-2014, CGC began benchmarking Nora Lateral purchases based on Transco Zone 5 index prices. As shown previously in Figure 7, Transco Zone 5 is in close proximity to the Nora Lateral, and ETNG is interconnected with Transco in Zone 5. The spot market purchases made by CGC from Range and Sequent during the winter of 2014-2015 were also benchmarked using Transco Zone 5 index prices.

Recently, *Inside FERC* and *Gas Daily* have subdivided the Transco Zone 5 index into Transco Zone 5 delivered South and Transco Zone 5 delivered North. The Transco Zone 5 delivered South index is applicable for purchases at the ETNG/Transco interconnect, and is also the index location in closest proximity to the Nora Lateral.

3.1.3 PBRM Performance

CGC's performance under the PBRM is included in the *Annual Report of Actual Cost of Gas Purchased and Applicable Indices* filed with the TRA each year for each Plan Year. As part of Exeter's review, a selected sample of CGC's benchmark and actual cost calculations was reviewed for accuracy and compliance with the terms of the PBRM. Our review found no discrepancies in CGC's calculations.

CGC's performance under the PBRM by purchase type and location is summarized in Table 4. Purchase types and locations include Gulf Coast production area monthly baseload and daily purchases, monthly in-ground storage inventory purchases, monthly Nora Lateral baseload purchases, daily purchases of Texas Eastern supplies at Mt. Pleasant, and daily Transco Zone 5 priced purchases.[3] As shown in Table 4, CGC's Plan Year actual commodity gas costs did not exceed benchmark commodity gas costs by more than one percent during the 2013 through 2015 Plan Years ended June 30. However, actual commodity costs exceeded benchmark commodity costs in the Plan Year ended June 30, 2016 by 3.27 percent. As subsequently discussed, this occurred due to the significant commodity adders required for the purchase of firm gas supplies to fill CGC's open ETNG firm transportation capacity with Nora Lateral receipt entitlements.

As shown in Table 4, there was essentially no variation between CGC's monthly baseload actual gas costs and benchmark gas costs for Gulf Coast purchases. This is because CGC purchased these supplies from Sequent under AMAs that provided for these purchases to be made at applicable monthly index prices. For the same reason, there was little variation between CGC's daily actual gas costs and benchmark costs for Gulf Coast purchases. The variations that did exist were generally associated with SONAT purchases that were injected into storage. The benchmark used for these purchases included the variable transportation charge associated with delivering gas to storage; however, these variable charges are not included in the actual cost of gas charged to CGC by Sequent that is compared to the benchmark. The variable charges associated with delivering gas to SONAT storage are paid directly to SONAT by CGC. Although the impact of including these variable charges in the benchmark was not significant during the review period, Exeter finds inclusion of these variable charges in the benchmark to

[3] Daily Transco Zone 5 priced purchases included spot market purchases from Range to fill CGC's open ETNG Nora Lateral capacity, and spot market purchases from Sequent, both made during the winter of 2014-2015.

Table 4.
CHATTANOOGA GAS COMPANY
Summary of Performance under the PBRM

	Plan Year[i]			
	3 M/E June 2013	**2014**	**2015**	**2016**
Monthly (Gulf Coast)				
Performance[ii]	$0	$0	($495)	$0
Volume (Dth)	44,780	2,851,219	3,690,889	1,950,038
Unit Variance per Dth	$0.0000	$0.0000	($0.0000)	$0.0000
Monthly Storage (In-ground)				
Performance[ii]	$0	$0	$0	$132
Volume (Dth)	919,536	655,526	0	819,649
Unit Variance per Dth	$0.0000	$0.0000	$0.0000	$0.0002
Monthly Nora Lateral				
Performance[ii]	$0	$13,216	$0	$596,098
Volume (Dth)	0	756,510	0	1,217,120
Unit Variance per Dth	$0.0000	$0.0175	$0	$0.4898
Daily (Gulf Coast)				
Performance[ii]	($10,960)	($21,972)	($9,964)	($19,914)
Volume (Dth)	1,175,200	5,495,728	4,647,090	3,698,822
Unit Variance per Dth	($0.0093)	($0.0040)	($0.0021)	($0.0054)
Texas Eastern Daily				
Performance[ii]	$0	($11,371)	$0	$0
Volume (Dth)	0	103,996	0	0
Unit Variance per Dth	$0	($0.1093)	$0	$0
Transco Zone 5[iii]				
Performance[ii]	$0	$0	($277,253)	$0
Volume (Dth)	0	0	121,167	0
Unit Variance per Dth	$0	$0	($2.2882)	$0
Total[iv]				
Performance[ii]	**($10,960)**	**($19,802)**	**($287,217)**	**$576,316**
Volume (Dth)	**2,139,516**	**9,863,056**	**8,459,146**	**7,685,629**
Unit Variance per Dth	**($0.0051)**	**($0.0020)**	**($0.0340)**	**$0.0750**
Cost Over/Under Benchmark	**(0.13)%**	**(0.05)%**	**(1.00)%**	**3.27%**

[i] 12 months ended June unless indicated.
[ii] (+) Costs exceed benchmark; (-) Costs below benchmark.
[iii] Includes daily purchases to fill Nora Lateral capacity and Sequent spot market purchases.
[iv] Total may not be exact due to rounding. Totals include 77 Dth of AGL interruptible delivery service in the 2014 Plan Year under which costs exceeded the benchmark by $325.

be unreasonable because it does not provide for a proper comparison of actual and benchmark costs, and Exeter recommends that these variable charges be excluded from the benchmark.

The actual costs of CGC's monthly in-ground storage inventory purchases, or transfers, from Sequent showed essentially no variance from benchmark costs. The benchmark for these purchases is based on applicable monthly index prices plus the variable pipeline transportation and storage injection charges. During the review period, these in-ground storage purchases were made under the CGC's TGP FS-MA and FS-PA storage arrangements.

During the Plan Year ended June 30, 2014, CGC's monthly baseload Nora Lateral firm purchases were made at prices slightly in excess of the TGP Zone L 500 Leg benchmark used by CGC at that time. Under this arrangement, purchases were priced based on NYMEX settlement prices plus a commodity adder that, on average, slightly exceeded the TGP Zone L 500 Leg benchmark and the related variable charges. For the Plan Year ended June 30, 2016, Nora Lateral firm purchases were benchmarked based on Transco Zone 5 index prices.[4] CGC's actual commodity costs significantly exceeded benchmark commodity costs for this Plan Year due to the significant commodity adders required under this arrangement, as discussed in Section 2.3.3 of the Report.

CGC's daily purchases at the Texas Eastern/ETNG interconnect during the winter of 2013-2014 were priced based on Texas Eastern Zone M-1 index prices and benchmarked based on the same index price. Actual costs for these purchases were slightly less than the benchmark costs because it appears that Sequent failed to include the Texas Eastern variable transportation charges that were eligible for inclusion in the price charged to CGC. These variable transportation charges were appropriately included in the benchmark.

The cost of CGC's Transco Zone 5 daily spot market purchases from Range and Sequent during the winter of 2014-2015 were significantly less than the benchmark costs. This was almost entirely due to the price for the Sequent spot market purchases being less than Transco Zone 5 index prices during February 2015. For most days on which these purchases were made in February 2015, the supplies were sourced from the Transco/ETNG interconnect in Transco Zone 5. Therefore, these purchases were

[4] The Nora Lateral contract included prices based on monthly NYMEX settlement prices. During the period under review, Transco Zone 5 index prices and NYMEX settlement prices were generally comparable.

appropriately benchmarked based on Transco Zone 5 index prices. However, during the period February 21-23, 2015, these supplies were purchased on a delivered-to-citygate basis to an ETNG meter and not sourced from Transco Zone 5. The source of the gas for these citygate purchases was not explicitly known. When the source of the gas is not known, the benchmark should be based on the citygate meter at which the supplies were delivered. For ETNG citygate meters, an appropriate benchmark to use would be TGP Zone L 500 Leg index prices adjusted for the applicable variable transportation charges because these purchases would have been delivered to CGC by ETNG and TGP. For SONAT citygate meters, an appropriate benchmark would be SONAT Louisiana index prices adjusted for the applicable variable transportation charges. Using TGP Zone L 500 Leg index prices to benchmark the citygate purchases made during the period February 21-23, 2015, would have decreased the negative difference between benchmark and actual costs shown in Table 4 for the Plan Year ended June 30, 2015 by approximately $180,000. However, even with this reduction, CGC's actual costs for that Plan Year would have remained below benchmark costs.

CGC's only firm citygate purchase arrangement during the review period was with Twin Eagle. CGC did not make citygate purchases under this arrangement during the review period.

Table 5 provides a comparison of the monthly *Inside FERC* index prices for the four primary receipt point locations under CGC's firm transportation arrangements with TGP and SONAT. Also shown for comparison purposes are monthly NYMEX settlement prices and TGP index prices for gas supply purchases in the Marcellus production region (TGP Zone 4 200 Leg). The TGP Zone 4 200 Leg is a relatively new published location and, therefore, information for the entire review period is not available. As shown in Table 5, the index prices at these four primary locations did not vary significantly from one another. If the variable costs of delivering supplies from each of these four primary receipt point locations is considered, prices at these locations, and in particular the TGP locations, on average, varied by only a few cents, with TGP Zone 0 purchases being the least expensive location. The delivered cost of monthly SONAT supplies was generally higher than TGP/ETNG delivered supplies regardless of the TGP purchase index location. *Gas Daily* index prices for daily purchases exhibited the same relationship.

In addition to the benchmark prices shown in Table 5, Texas Eastern Zone M-1 index prices were used to benchmark purchases at the Texas Eastern/ETNG Mt. Pleasant interconnect, and Transco Zone 5 index prices were used to price ETNG Nora Lateral and Sequent spot market purchases for a portion of the audit period. Although not presented in Table 5, during the Plan Year ended June 30, 2016, Transco Zone 5 monthly index prices averaged approximately 25 cents per Dth higher than NYMEX settlement prices and 35 cents per Dth higher than Texas Eastern Zone M-1 monthly index prices. Differences in Transco and Texas Eastern and NYMEX settlement prices were much more significant during the winter than during the summer. On a daily basis, Transco Zone 5 index prices averaged 20 cents per Dth higher than Henry Hub prices (as a proxy for NYMEX settlement prices), while Texas Eastern Zone M-1 daily prices averaged 7 cents per Dth less than Henry Hub prices. During the winter of 2013-2014, when CGC purchased gas at the Texas Eastern/ETNG interconnect, TGP Zone 0 index prices were, on average, several cents less than Texas Eastern Zone M-1 index prices.

Table 5.
CHATTANOOGA GAS COMPANY
Summary of Prices by Pipeline Location – *Inside FERC* First-of-the-Month Index Prices
($/Dth)

	Tennessee Gas Pipeline				Southern	NYMEX
Month	**Zone 0**	**ZL 100/500 Leg**	**ZL 800 Leg**	**Z4 200 Leg**	**Natural**	**Settlement**
April 2013	$3.90	$3.98	$3.95	N/A	$3.98	$3.98
May	4.10	4.26	4.13	N/A	4.16	4.15
June	4.07	4.17	4.12	N/A	4.17	4.15
July 2013	$3.61	$3.71	$3.67	N/A	$3.71	$3.70
August	3.36	3.42	3.41	N/A	3.42	3.46
September	3.46	3.52	3.51	N/A	3.54	3.57
October	3.41	3.46	3.45	N/A	3.47	3.50
November	3.41	3.47	3.45	N/A	3.49	3.50
December	3.68	3.76	3.73	N/A	3.78	3.82
January 2014	4.26	4.36	4.35	N/A	4.37	4.41
February	5.26	5.57	5.49	N/A	5.55	5.56
March	4.65	4.82	4.79	N/A	4.80	4.86
April	4.45	4.55	4.52	N/A	4.56	4.58
May	4.65	4.75	4.72	N/A	4.77	4.80
June	4.45	4.57	4.54	N/A	4.58	4.62
Yearly Average	$4.05	$4.16	$4.14	N/A	$4.17	$4.20
Variable Delivered	$4.22	$4.32	$4.30	N/A	$4.45	N/A
July 2014	$4.28	$4.38	$4.34	N/A	$4.38	$4.40
August	3.68	3.77	3.73	N/A	3.78	3.81
September	3.85	3.92	3.91	N/A	3.94	3.96
October	3.86	3.93	3.93	N/A	3.96	3.98
November	3.57	3.67	3.64	$3.36	3.69	3.73
December	4.15	4.25	4.22	3.51	4.28	4.28
January 2015	3.05	3.17	3.12	2.24	3.17	3.19
February	2.73	2.85	2.80	2.67	2.86	2.87
March	2.76	2.89	2.85	2.66	2.88	2.89
April	2.46	2.54	2.52	1.72	2.59	2.59
May	2.41	2.49	2.45	1.51	2.49	2.52
June	2.72	2.79	2.76	1.59	2.79	2.82
Yearly Average	$3.29	$3.39	$3.36	N/A	$3.40	$3.42
Variable Delivered	$3.44	$3.52	$3.49	N/A	$3.64	N/A
July 2015	$2.68	$2.75	$2.72	$1.36	$2.76	$2.77
August	2.80	2.86	2.84	1.45	2.86	2.89
September	2.54	2.60	2.58	1.56	2.61	2.64
October	2.46	2.50	2.48	1.60	2.52	2.56
November	1.94	1.97	1.95	1.50	2.00	2.03
December	2.15	2.15	2.15	1.79	2.18	2.21
January 2016	2.30	2.34	2.34	1.68	2.36	2.37
February	2.13	2.16	2.15	1.58	2.17	2.19
March	1.63	1.66	1.64	1.11	1.67	1.71
April	1.82	1.84	1.83	1.33	1.85	1.90
May	1.90	1.92	1.91	1.40	1.95	2.00
June	1.86	1.89	1.88	1.47	1.91	1.96
Yearly Average	$2.18	$2.22	$2.21	$1.33	$2.24	$2.27
Variable Delivered	$2.29	$2.32	$2.31	N/A	$2.42	N/A

Table 6 provides a comparison of CGC's monthly and daily purchases at each of the Company's four primary receipt point locations. As shown, consistent with least-cost procurement, CGC maximized the purchase of TGP Zone 0 supplies, its lowest-cost supply, generally by baseloading these supplies on a monthly basis, and relying on its higher-cost supplies to meet incremental daily purchase requirements.

Table 6.
CHATTANOOGA GAS COMPANY
Summary of Monthly and Daily Purchases by Primary Receipt Point Locations
(Dth)

	Plan Year					
Location	**3 M/E June 2013**	**2014**	**2015**	**2016**	**Total**	**Percent**
MONTHLY						
TGP Zone 0	44,780	2,445,895	3,427,814	1,112,498	7,030,987	82.4%
TGP Zone L 100/500 Leg	0	0	0	0	0	0.0
TGP Zone L 800 Leg	0	243,721	263,075	550,024	1,056,820	12.4
SONAT	0	161,603	0	287,516	449,119	5.3
Subtotal Monthly:	44,780	2,851,219	3,690,889	1,950,038	8,536,926	100.0%
DAILY						
TGP Zone 0	8,056	627,374	430,565	711,178	1,777,173	11.8%
TGP Zone L 100/500 Leg	0	432,652	79,690	75,156	587,498	3.9
TGP Zone L 800 Leg	886,659	2,109,812	1,067,153	1,283,006	5,346,630	35.6
SONAT	280,485	2,325,890	3,069,682	1,629,482	7,305,539	48.6
Subtotal Daily:	1,175,200	5,495,728	4,647,090	3,698,822	15,016,840	100.0%
TOTAL						
TGP Zone 0	52,836	3,073,269	3,858,379	1,823,676	8,808,160	37.4%
TGP Zone L 100/500 Leg	0	432,652	79,690	75,156	587,498	2.5
TGP Zone L 800 Leg	886,659	2,353,533	1,330,228	1,833,030	6,403,450	27.2
SONAT	280,485	2,487,493	3,069,682	1,916,998	7,754,658	32.9
Total:	**1,219,980**	**8,346,947**	**8,337,979**	**5,648,860**	**23,553,766**	**100.0%**

3.2 Nora Lateral Index Price

A requirement of the expanded scope of review of this audit is to provide an analysis and recommend the appropriate PBRM benchmark to be used to evaluate the purchases of gas supplies to fill CGC's open ETNG capacity on the Nora Lateral. Benchmarks under the PBRM are determined based on published index prices. CGC purchased firm monthly baseload supplies delivered to the Nora Lateral for the winters of 2013-2014 and 2015-2016. For the winter of 2014-2015, CGC attempted but was unable to purchase firm monthly baseload gas supplies to fill its ETNG Nora Lateral capacity, and relied on daily spot market purchases when these supplies were available. As explained Section 2.3.3, CGC purchased monthly baseload supplies to fill its Nora Lateral capacity for the annual period April 2016 – March 2017. Purchases under CGC's contracts for Nora Lateral monthly baseload gas supplies were priced based on NYMEX settlement prices plus a commodity adder. For the winter of 2013-2014, the commodity adder was $0.06 per Dth, for the winter of 2015-2016, the commodity adder was $1.045 per Dth, and for the annual period April 2016 – March 2017, the commodity adder was $0.51 cents per Dth. The significant commodity adders for the winter of 2015-2016 and the annual period April 2016 – March 2017 caused CGC's commodity costs to exceed benchmark costs under the PBRM by more than one percent, triggering the prudence review required under TRA Administrative Rule 1220-4-7-.05(1)(a).

For the winter of 2013-2014, TGP Zone L 500 Leg monthly index prices were used by CGC to establish the PBRM benchmark for Nora Lateral supplies. For the winter of 2015-2016 and the annual period April 2016 – March 2017, monthly Transco Zone 5 index prices were used to establish the benchmark. Daily Transco Zone 5 index prices were used to establish the benchmark for Nora Lateral spot market purchases during the winter of 2014-2015.

Index prices are published for liquid trading locations. Liquidity refers to the extent to which gas is actively traded by multiple suppliers and purchasers and, therefore, prices are established in a competitive manner. While Transco Zone 5 is a liquid trading location and the Nora Lateral is in close proximity to Transco Zone 5, the Nora Lateral is not a liquid trading location. This is because only one major producer has production facilities that deliver gas to the Nora Lateral (see Section 2.3.3). While CGC continues to examine opportunities to replace or move its primary Nora Lateral receipt point to another more liquid location, it has been unable to do so.

In Exeter's view, the newly established Transco Zone 5 delivered South index price could be used to establish Nora Lateral monthly or daily benchmark costs under the PBRM. In the alternative, monthly NYMEX settlement prices that have historically been used to price monthly Nora Lateral baseload purchases could be used to establish the Nora Lateral monthly benchmark costs, and daily Henry Hub index prices could be used to establish Nora Lateral daily benchmark costs. Over the last year, Transco Zone 5 delivered South and NYMEX settlement (or Henry Hub) prices have generally varied by no more than a few cents and, therefore, use of either indexing option would produce similar benchmark costs. While use of either the Transco Zone 5 delivered South or Henry Hub index prices would be appropriate for daily spot market purchases, neither index would address the substantial premium currently required for Nora Lateral monthly baseload supplies or address the prudence of those purchases. Because of its close proximity to Transco Zone 5, Exeter recommends that future Nora Lateral daily spot purchases be benchmarked based on Transco Zone 5 delivered South index prices.

The PBRM includes a provision for adjusting the benchmark used for long-term purchases (i.e., arrangements with a term of more than one month) to reflect a three-year rolling average of the premium paid to ensure long-term supply availability during peak periods. The firm monthly purchase arrangements relied on to fill CGC's open ETNG Nora Lateral capacity may qualify as long-term purchases that are needed during peak periods. However, three years of data are not available to calculate a three-year rolling average premium. In addition, the pricing premium data that is available has revealed that the premium can change substantially from year to year and, therefore, would unlikely provide a reasonable assessment of the prudence of CGC's Nora Lateral monthly baseload supply purchases. Exeter concludes that an appropriate benchmark that evaluates prudence for monthly baseload Nora Lateral purchases cannot be reasonably established under the PBRM.

To address the prudence of CGC's monthly baseload Nora Lateral purchases, Exeter recommends that these purchases be excluded from the PBRM, and that CGC be required to report to the Commission on an annual basis its efforts to reduce the costs associated with Nora Lateral monthly baseload purchases. CGC should file these reports with its annual PBRM filings. Based on these annual reports, the Commission can determine an appropriate course of action.

4.0 STORAGE ACTIVITY AND OFF-SYSTEM LNG SALES

The scope of this investigation, as stated in the RFP, requires the review of CGC's actual gas procurement transactions and costs, including storage activity, as reported in the Company's PBRM and Actual Cost Adjustment filings. The ACA filings provide for a reconciliation of CGC's actual gas costs and gas cost revenues. CGC's ACA filings include the actual purchases and costs reflected in CGC's PBRM filings. CGC's monthly baseload and daily gas supply purchase transactions were reviewed in Section 3.0 of the Report. This section of the Report reviews CGC's storage activity, including its in-ground storage inventory purchase activity with Sequent, as well as CGC's LNG off-system sales activities.

4.1 Storage Arrangements

As discussed in greater detail in Sections 2.1.1 and 2.1.3 of the Report, CGC maintained contract storage service with TGP and SONAT during the review period. The FS-MA and FS-PA arrangements with TGP provided for an MDQ of 21,400 Dth per day and a maximum winter season deliverability of 2,894,676 Dth. CGC's storage service arrangement under Rate Schedule CSS provided for an MDQ of 14,346 Dth per day and a maximum winter season deliverability of 710,484 Dth. CGC's SONAT CSS storage arrangement includes deliverability ratchets under which the MDQ is reduced as storage inventory declines as follows:

Storage Inventory Balance	Percent of MDQ
60 – 100%	100%
50-59	88
25-49	78
0-24	56

In total, the MDQ of CGC's contract storage services was 35,746 Dth, and the maximum winter season deliverability was 3,605,160 Dth.

In addition to its contract storage services from TGP and SONAT, CGC operates an LNG facility. The LNG facility was capable of producing up to 90,400 Dth per day for an estimated 13 days. Table 7 identifies the monthly storage activity (injections/withdrawals) and the inventory balances under each of CGC's interstate pipeline contract storage arrangements and its LNG facility at the conclusion of each month of the audit period. Also identified in Table 7 are CGC's storage inventory balances as a percent of the Company's maximum seasonal contract quantity or capacity. Under the AMAs, Sequent, acting as the agent for CGC, was entitled to generate economic gain by managing a portion of CGC's gas inventory under CGC's contracts with its interstate pipelines, as long as Sequent met CGC's requirements in the manner directed by CGC. The storage to which Sequent has access was designated as optimization inventory. While the gas was designated as optimization inventory, CGC was entitled to access this inventory and use it if it was necessary for CGC to meet customer requirements. The optimization inventory balances managed by Sequent for asset optimization purposes, are also identified in Table 7.

4.2 Storage Planning Guidelines

CGC generally fills its storage capacity during the summer months (April – October). Under the terms of the AMA, CGC is required to ratably fill its Tennessee FS-PA and FS-MA storage. That is, CGC is required to inject the same daily quantity during the summer injection period. Such a requirement is common under an AMA. CGC is not required to fill its SONAT CSS or LNG storage on a ratable basis. The monthly storage injection activity reflected in Table 7 is generally consistent with these requirements. CGC depletes storage inventory during the winter months (November – March). In addition to dispatching gas for storage injection or withdrawal, CGC engages in storage inventory transfers. Under CGC's transportation arrangements with SONAT, differences between the Company's nominated supplies and actual deliveries are reconciled through no-notice storage injections or withdrawals.

CGC has established storage planning guidelines that identify the inventory levels the Company plans to maintain. The planned inventory levels at the start of the storage injection season (April 1) and the planned inventory levels at the start of the storage withdrawal season (November 1), as well as CGC's actual inventory levels during the review period, are identified in Table 8. As shown in Table 8, CGC plans to fill its contract storage services to 80-90 percent of capacity prior to the beginning of the storage withdrawal season on November 1 of each year. This provides CGC the ability to inject gas into storage during November if warmer-than-normal weather is experienced. CGC increased its planned LNG facility fill level to 100 percent of capacity during the review period to accommodate the potential for increased demand for off-system LNG sales. These off-system sales are subsequently discussed in Section 4.4.

Table 7.
CHATTANOOGA GAS COMPANY
Summary of Audit Period End-of-Month Storage Inventory Balances
(Dth)[i]

	TENNESSEE GAS PIPELINE (FS-PA)			TENNESSEE GAS PIPELINE (FS-MA)			TGP FS-PA/MA	SOUTHERN NATURAL GAS (CSS)[ii]				LIQUEFIED NATURAL GAS[iii]			
	Chattanooga Gas			Chattanooga Gas			Optimization	Chattanooga Gas			Optimization	Chattanooga Gas			Optimization
	Activity	Inventory	% Full	Activity	Inventory	% Full	Inventory	Activity	Inventory	% Full	Inventory	Activity	Inventory	% Full	Inventory
April 2013	(123,050)	345,303	17%	(89,580)	127,251	15%	1,637,051	(49,189)	117,082	16%	129	28,401	754,983	63%	300,356
May	(234,329)	579,632	28	(93,434)	220,685	26	1,321,622	(93,036)	210,118	30	129	16,034	738,949	61	305,856
June	(226,770)	806,402	39	(90,420)	311,105	37	1,016,972	(2,948)	213,066	30	129	20,938	718,011	59	305,172
July	(234,329)	1,040,731	51	(93,434)	404,539	47	669,026	(125,660)	338,726	48	129	16,996	701,015	58	301,672
August	(234,329)	1,275,060	62	(93,434)	497,973	58	267,080	(134,844)	473,570	67	129	(73,612)	774,627	64	291,772
September	(226,770)	1,501,830	74	(90,420)	588,393	69	267,080	(126,728)	600,298	84	129	(174,815)	949,442	79	300,414
October	(226,580)	1,728,410	85	(93,434)	681,827	80	419,320	(32,149)	632,447	89	129	70,563	878,879	73	284,453
November	175,664	1,552,746	76	38,159	643,668	76	410,583	78,277	554,170	78	129	(9,213)	888,092	74	280,753
December	288,643	1,264,103	62	133,975	509,693	60	423,636	76,805	477,365	67	129	97,443	790,649	65	224,977
January 2014	494,938	769,165	38	204,380	305,313	36	179,395	17,016	460,349	65	129	609,575	181,074	15	131,374
February	432,469	336,696	16	178,120	127,193	15	240,369	(36,882)	497,231	70	129	(85,624)	266,697	22	95,564
March	243,684	93,012	5	103,359	23,834	3	309,252	67,336	429,895	60	129	(265,869)	532,566	44	91,773
April 2014	(216,210)	309,222	15%	(91,650)	115,484	14%	305,965	(16,244)	446,139	63%	129	13,750	518,816	43%	86,904
May	(652,763)	961,985	47	(95,418)	210,902	25	305,965	(87,739)	533,878	75	129	(37,475)	556,291	46	167,904
June	(151,770)	1,113,755	55	(92,340)	303,242	36	305,965	(62,380)	596,258	84	129	(148,093)	704,384	58	190,981
July	(284,552)	1,398,307	68	(95,418)	398,660	47	303,237	(20,442)	616,700	87	129	(147,677)	852,061	71	210,438
August	(115,289)	1,513,596	74	(95,418)	494,078	58	303,237	16,844	599,856	84	129	(111,313)	963,374	80	235,278
September	(111,570)	1,625,166	80	(92,340)	586,418	69	303,237	(32,790)	632,646	89	129	32,819	930,555	77	232,928
October	(110,887)	1,736,053	85	(95,387)	681,805	80	302,420	(2,308)	634,954	89	129	37,344	893,211	74	176,928
November	144,050	1,592,003	78	32,896	648,909	76	314,232	47,004	587,950	83	129	127,388	765,823	63	219,727
December	346,403	1,245,600	61	118,620	530,289	62	525,954	25,080	562,870	79	129	(111,274)	877,097	73	198,227
January 2015	387,414	858,186	42	212,618	317,671	37	537,394	171,010	391,860	55	129	17,233	859,864	71	130,411
February	382,452	475,734	23	170,464	147,207	17	503,008	125,700	266,160	37	129	272,033	587,831	49	77,647
March	170,930	304,804	15	91,268	55,939	7	362,173	84,960	181,200	25	129	(117,836)	705,667	58	77,660
April 2015	(196,350)	501,154	25%	(88,170)	144,109	17%	362,173	(8,776)	189,976	27%	129	(185,885)	891,552	74%	105,660
May	(220,162)	721,316	35	(90,582)	234,691	28	396,533	(76,768)	266,744	38	129	8,311	883,241	73	152,100
June	(201,369)	922,685	45	(87,660)	322,351	38	396,533	(123,576)	390,320	55	129	40,144	843,097	70	123,100
July	(205,003)	1,127,688	55	(90,582)	412,933	48	259,780	(77,666)	467,986	66	129	(127,821)	970,918	80	99,468
August	(205,003)	1,332,691	65	(90,613)	503,546	59	97,991	(92,557)	560,543	79	129	(171,077)	1,141,995	95	72,468
September	(198,420)	1,531,111	75	(87,630)	591,176	69	97,991	(66,912)	627,455	88	129	37,349	1,104,646	91	32,468
October	(205,034)	1,736,145	85	(90,551)	681,727	80	2,356	1,106	626,349	88	1,877	(94,278)	1,198,924	99	0
November	134,542	1,601,603	78	38,790	642,937	75	191,931	22,025	604,324	85	1,877	31,113	1,167,811	97	0
December	206,184	1,395,419	68	88,210	554,727	65	453,224	107,820	496,504	70	1,877	34,697	1,133,114	94	0
January 2016	484,859	910,560	45	174,794	379,933	45	600,955	55,109	441,395	62	1,877	211,437	921,677	76	0
February	289,265	621,295	30	173,079	206,854	24	746,901	131,118	310,277	44	1,877	118,490	803,187	67	0
March	344,705	276,590	14	148,086	58,768	7	1,085,981	123,749	186,528	26	1,877	(243,024)	1,046,211	87	0
April 2016	(205,110)	481,700	24%	(87,090)	145,858	17%	894,342	45,810	140,718	20%	1,907	(123,665)	1,169,876	97%	0
May	(211,358)	693,058	34	(90,272)	236,130	28	1,187,336	(80,366)	221,084	31	1,748	(143,177)	1,313,053	109	0
June	(252,800)	945,858	46	(87,360)	323,490	38	1,112,451	(111,191)	332,275	47	1,748	52,353	1,260,700	104	0
Maximum Seasonal Inventory:		**2,042,390**			**852,286**				**710,848**				**1,207,574**		

[i] Negative monthly activity reflects injections; positive monthly activity reflects withdrawals. Monthly activity includes inventory transfers.
[ii] Includes cashouts.
[iii] Volumes in Mcf.

Table 8.
CHATTANOOGA GAS COMPANY
Planned and Actual Storage Inventory as a Percent of Seasonal Capacity

	April 1		November 1	
	Planned	Actual	Planned	Actual
2013				
SONAT CCS	10%	10%	90%	89%
TGP FS-PA	10	11	85	85
TGP FS-MA	5	4	80	80
LNG	55	65	75	73
2014				
SONAT CCS	10%	60%	90%	89%
TGP FS-PA	10	5	85	85
TGP FS-MA	5	3	80	80
LNG	55	44	75	74
2015				
SONAT CCS	10%	25%	90%	88%
TGP FS-PA	10	15	85	85
TGP FS-MA	5	7	80	80
LNG	55	58	100	99
2016				
SONAT CCS	10%	26%	N/A	N/A
TGP FS-PA	10	14	N/A	N/A
TGP FS-MA	5	7	N/A	N/A
LNG	55	87	N/A	N/A

By the conclusion of the storage withdrawal season, CGC plans on depleting its contract storage inventories to 5-10 percent of capacity. CGC plans to deplete its LNG inventory to 55 percent of capacity prior to the conclusion of the storage withdrawal season. This level of LNG inventory is consistent with the inventory level that would remain after filling LNG to planned levels and vaporizing the supplies necessary to meet requirements under severe winter weather conditions. CGC does not plan on cycling LNG inventory as it does with contract storage because of the significant fuel requirements associated with liquefying gas supplies. CGC's storage planning guidelines are consistent with those of other gas utilities and appear reasonable.

At the conclusion of the winter of 2012-2013 (April 1, 2013), CGC's contract and LNG storage was depleted to levels consistent with its planning criteria and was subsequently refilled consistent with those criteria prior to the winter of 2013-2014. Storage was generally also depleted to planned inventory levels at the conclusion of the winter of 2013-2014 with the exception of SONAT CSS which was depleted to 60 percent of capacity. This higher-than-planned inventory balance is discussed in the following section. Storage was refilled to planned levels prior to the winter of 2014-2015, and generally depleted to planned levels at the conclusion of that winter. Storage was refilled consistent with CGC's planning criteria prior to the winter of 2015-2016, and generally depleted to planned inventory levels at the conclusion of that winter.

CGC's storage inventory planning criteria were reasonable and CGC generally adhered to those criteria. Therefore, CGC's review period storage activity appears reasonable.

4.3 <u>In-ground Storage Purchases and Transfers</u>

As indicated in Section 3.1.1 of the Report, CGC made a number of in-ground storage inventory purchases from Sequent during the review period. These in-ground storage inventory purchases are summarized in Table 9. At times, these in-ground storage inventory purchases reflect a transfer of gas from optimization inventory to CGC, and at other times reflected the transfer of gas in storage held by Sequent under storage arrangements other than the CGC TGP and SONAT arrangements made available under the AMA. As shown in Table 9, these transfers generally occurred during the summer injection period. The in-ground storage inventory transfers were invoiced at costs that were equivalent to the costs CGC would have incurred if the gas had been purchased in the Gulf Coast production region and delivered to and injected into storage.

In addition to in-ground storage inventory purchases, CGC made pipeline storage inventory transfers during the review period. These included transfers of storage inventory between its TGP FS-PA and SONAT CSS arrangements. These transfers were possible because TGP FS-PA and SONAT CSS storage services are both provided from the Bear Creek storage facility located in Louisiana, which is a joint venture equally owned by TGP and SONAT. The higher-than-planned SONAT CSS inventory balance at the conclusion of the winter of 2013-2014 was attributable to TGP FS-PA to SONAT CSS inventory transfers made in January and February 2014. These transfers were made to maintain the MDQ of CSS and avoid the triggering of storage deliverability ratchets. Much colder than normal weather was experienced during January and February 2014, which resulted in the sooner-than-planned depletion of CSS storage inventory.

Table 9.
CHATTANOOGA GAS COMPANY
Summary of Monthly In-ground Storage Purchases
(Dth)

	TGP FS-PA		TGP FS-MA	
	Quantity (Dth)	Price ($/Dth)	Quantity (Dth)	Price ($/Dth)
April 2013	209,850	$4.0579	89,580	$4.0593
May	222,022	4.2643	93,434	4.2657
June	214,860	4.2333	89,790	4.2347
July	234,329	3.7586	93,434	3.7600
August	234,329	3.5006	93,434	3.5020
July 2015	205,003	2.7710	90,582	2.7724
August	85,994	2.8932	75,795	2.8946
October	22,692	2.5469	72,943	2.5483
April 2016	150,780	1.8922	40,860	1.8936
June	52,290	1.9483	22,710	1.9551

CGC also made other storage inventory transfers during the review period. These transfers were primarily adjustments to SONAT CSS storage to reconcile monthly differences between actual and nominated deliveries to CGC.

4.4 Off-system LNG Sales

CGC engaged in off-system LNG tanker sales during the review period through its affiliate, Pivotal LNG, Inc. (Pivotal). Pivotal is engaged in the sale of LNG as a substitute fuel for transportation and other mechanical uses in the wholesale LNG market. Pivotal received no direct compensation for acting on behalf of CGC. The margins from CGC's LNG tanker sales are shared 50 percent with ratepayers, and the margins are reflected in the Company's Interruptible Margin Credit Rider (IMCR) filings made at the end of each May for the 12-month period ended the prior March 31.

The LNG supplies marketed by Pivotal are initially purchased from Sequent. Initially during the review period, through October 2015, the margins from CGC's LNG off-system sales activities consisted of two components: (1) margins realized on the sale of gas by Sequent to Pivotal; and (2) margins realized by Pivotal when the gas is sold in the wholesale LNG market. The gas sold to Pivotal by Sequent was priced based on SONAT index prices (monthly or daily, as applicable), adjusted to reflect the variable pipeline transportation charges associated with delivering gas from the Gulf Coast production area to CGC. Also included in the price were SONAT firm transportation demand charges calculated on a 100 percent load factor basis. These demand charges reflected the margins realized on the sale of gas by Sequent to Pivotal. Exeter's prior tri-annual audit noted that theses margins were at the time not being shared with ratepayers, and recommended that these margins be subject to sharing.

The margin realized by Pivotal when gas was sold in the wholesale LNG market was determined based on the difference between the revenues received from the sale, less the cost of gas sold. The cost of gas sold was based on the price paid to Sequent for the gas, adjusted to reflect the fuel used to liquefy the supply. Approximately 20 percent of each purchase is required for liquefaction fuel.

Effective November 1, 2015, the Company transferred gas to Pivotal, as agent, at cost. That is, SONAT demand charges were excluded from the margin calculation on transfers to Pivotal. This reduced the cost of gas sold in Pivotal's wholesale LNG transactions, and increased the margin from those transactions. On net, there was no difference in the margin associated with each transaction shared with customers. A summary of CGC's off-system LNG tanker sales activities and margins for the review period, as reported in its IMCR filings, is presented in Table 10.

Table 10. CHATTANOOGA GAS Company Summary of Off-system LNG Sales Margins		
	Sales to Pivotal by Sequent	
IMCR Period	**Volume (Mcf)**	**Margin**
March 31, 2014	198,600	$83,372
March 31, 2015	521,000	209,697
March 31, 2016[i]	378,558	86,948
Subtotal:	1,098,158	$380,017
	Wholesale Market Sales by Pivotal	
IMCR Period	**Volume (Mcf)**	**Margin**
March 31, 2014	208,734	$342,829
March 31, 2015	504,833	748,562
March 31, 2016	367,437	886,249
Subtotal:	1,081,004	$1,977,640
Total:		**$20,153,657**

[i] Beginning October 2015, sales to Pivotal were made at cost.

As a result of extreme, sustained cold weather in early 2014, the inventory of Atlanta Gas Light Company's (AGL) Cherokee LNG facility was depleted to a level that jeopardized the reliability of service. AGL is a CGC affiliate. To replenish the depleted inventory, 89,850 Dth of LNG was transferred by truck from CGC's LNG facility to the Cherokee LNG facility during January and February 2014. To compensate CGC for the LNG transferred to AGL, AGL transferred 119,122 Dth of gas into CGC's TGP FS-PA storage account at no cost to CGC in May 2014. The 119,122 Dth included 29,272 Dth for the fuel charges that were associated with delivering that gas to CGC's system and the liquefaction fuel that was required to convert that gas into 89,850 Dth of LNG. Exeter's review found that the utility mutual aid transaction with AGL did not appear to have an adverse impact on CGC's ability to serve its customers' needs or off-system LNG sales activities.

Utility mutual aid transactions are not common among gas utilities. However, when aid is provided, it should be done so in a manner that does not negatively affect the customers of the utility that is providing the assistance. When LNG was transferred to AGL by CGC, the market price of natural gas was higher than the market price when the gas was returned to CGC. Exeter estimates the difference in market value to be approximately $114,300. Exeter recommends that for future mutual aid transactions, compensation should be based on the economic value of the transaction, and not simply a return in-kind of the volume of gas that was supplied. Exeter defers to the TRA as to whether an adjustment to CGC's gas costs is warranted for the review period.

5.0 EVALUATION OF CAPACITY PORTFOLIO AND LOAD DURATION CURVES

5.1 Design Day Forecast

CGC secures sufficient capacity resources to meet the forecasted design day requirements of sales customers and those transportation customers that select firm backup service. CGC's design day is a day with a mean temperature of 8˚F (57 heating degree days [HDD]). In the last 87 years, there have been six occurrences where temperatures colder than 8˚F have been experienced. This equates to a design day probability of occurrence of approximately once every 15 years. This probability of occurrence is consistent with observed industry practices.

Separate design day forecasts are prepared for the sales and transportation customers in each of the Company's two service territories (Chattanooga and Cleveland). For the sales customer forecasts, CGC performs a regression analysis of historical daily data. The Company's regression analysis includes use-per-customer as the dependent variable, and current and prior day HDDs and Friday, Saturday, and Sunday weekend days as the independent variables. Bend points, which aid in capturing the measured change in customer consumption behavior at increasingly colder temperatures deemed to be of statistical significance, are also included as independent variables. The regression analysis is based on daily data from the core winter months (December – March) for the prior five years for days with at least one HDD.

For transportation customers selecting firm backup service, the contracted level of backup service is used for the Company's design day forecast. The Company's total design day forecast reflects the anticipated demands of sales customers and transportation customers selecting firm backup service, adjusted for new load additions. The Company's forecasted design day requirements by component for the winters of 2015-2016 and 2016-2017, each based on data from the prior five winter seasons, is summarized in Table 11.

A requirement of Exeter's audit is to analyze and evaluate the manner in which CGC includes the effect of energy conservation in its forecast of design day demands. The Company's design day forecast is prepared using the most recent five years of data, which CGC claims captures the effect of its customers' energy conservation and efficiency efforts over this time period. To assess the potential impact of customer conservation efforts on design day demands, Exeter prepared an independent design day forecast utilizing data from the three-year review period. Our forecast was nearly identical

Table 11.
CHATTANOOGA GAS COMPANY
Summary of Design Peak Day Requirements
(Dth)

Description	Chattanooga	Cleveland	Total
Winter 2015-2016			
Sales	110,260	15,447	**125,707**
Transport Firm Backup	18,106	2,227	**20,333**
Load Additions	640	107	**747**
Total:	**129,006**	**17,781**	**146,787**
Winter 2016-2017			
Sales	108,372	15,600	**123,972**
Transport Firm Backup	17,687	2,350	**20,037**
Load Additions	5,481	145	**5,626**
Total:	**131,540**	**18,095**	**149,635**

to that prepared by the Company. This suggests that conservation efforts have not had a significant impact on CGC's design day demands. It also supports the reasonableness of CGC's design day forecast. Gas utilities in other jurisdictions that explicitly evaluate the impact of energy efficiency and customer conservation efforts have found the annual impact on design day demands to be less than one percent per year.

5.2 Actual Peak Day Demands

Table 12 summarizes the requirements of CGC's sales and transportation customers on the actual peak day observed during each winter season of the review period. Also shown are actual heating degree days. On average during the review period, CGC's design day forecasting model has forecasted requirements under actual weather conditions within 2 percent. This further supports the reasonableness of the Company's model.

Table 12. CHATTANOOGA GAS COMPANY Summary of Actual Firm Peak Day Sendout (Dth)					
Year	**Peak Day**	**HDD**	**Chattanooga**	**Cleveland**	**Total**
2014	January 6, 2014	54.5	119,759	16,304	**136,063**
2015	February 19, 2015	48.3	107,577	17,016	**124,593**
2016	January 18, 2016	42.4	98,866	15,456	**114,322**

5.3 Balance of Capacity Resources and Customer Requirements

As initially shown on Table 1 in Section 2.1 of the Report, the capacity resources available to meet CGC's design day requirements for the 2015-2016 winter season totaled 159,321 Dth. This total was unchanged for the winter of 2016-2017. For the winter of 2016-2017, as shown previously in Table 11, projected design day requirements were 149,635 Dth. CGC attempts to maintain a capacity reserve margin of 5 percent, which Exeter does not find unreasonable. Estimated design day firm requirements, including the 5 percent reserve margin, totaled 157,117 Dth for the winter of 2016-2017, indicating that CGC's design peak day capacity resources and requirements were in relative balance.

The overall reasonableness of the balance between CGC's capacity portfolio resources and requirements can be assessed by load duration curves, which compare the daily demands of CGC's customers with the capacity resources available to meet those demands. Figure 8 and Figure 9 present load duration curves for CGC's Chattanooga and Cleveland service territories, respectively, under severe weather planning conditions, which CGC identifies as a year in which HDDs are 30 percent higher than normal. The demands reflected in Figure 8 and Figure 9 include purchases made for storage injection.[5]

As just explained, CGC design peak day capacity resources and requirements are in relative balance. However, Figure 8 and Figure 9 reveal that even under severe weather conditions, as noted by the capacity resources identified above severe weather load, CGC maintains capacity resources in excess of its requirements at most other times, particularly in the Cleveland service territory. During a

[5] Storage injections are reflected on days 152 through 365 (the storage injection period), and account for the spike in demand observed on day 152.

Figure 8.
CHATTANOOGA GAS COMPANY
Load Duration Curve – Chattanooga Service Territory

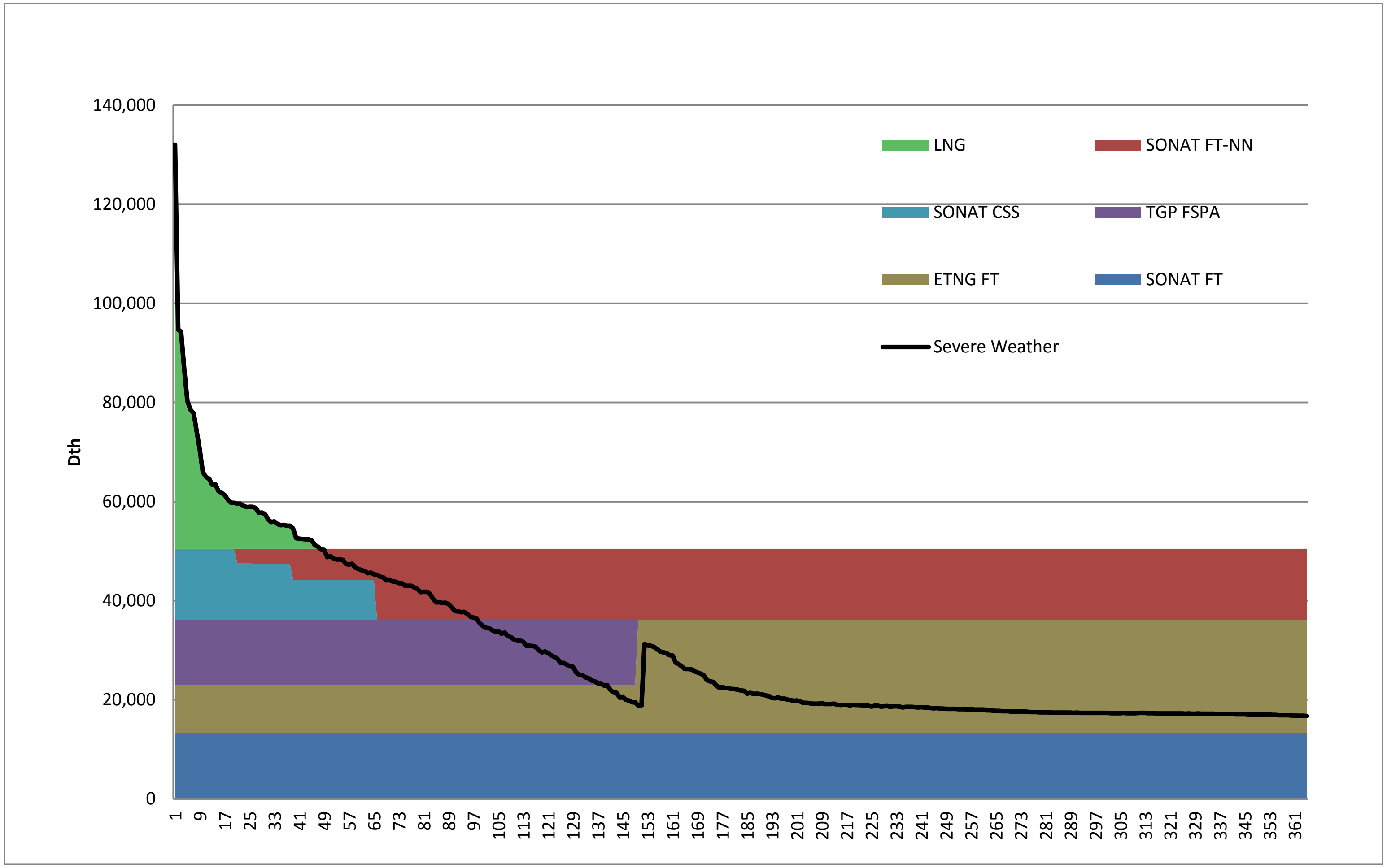
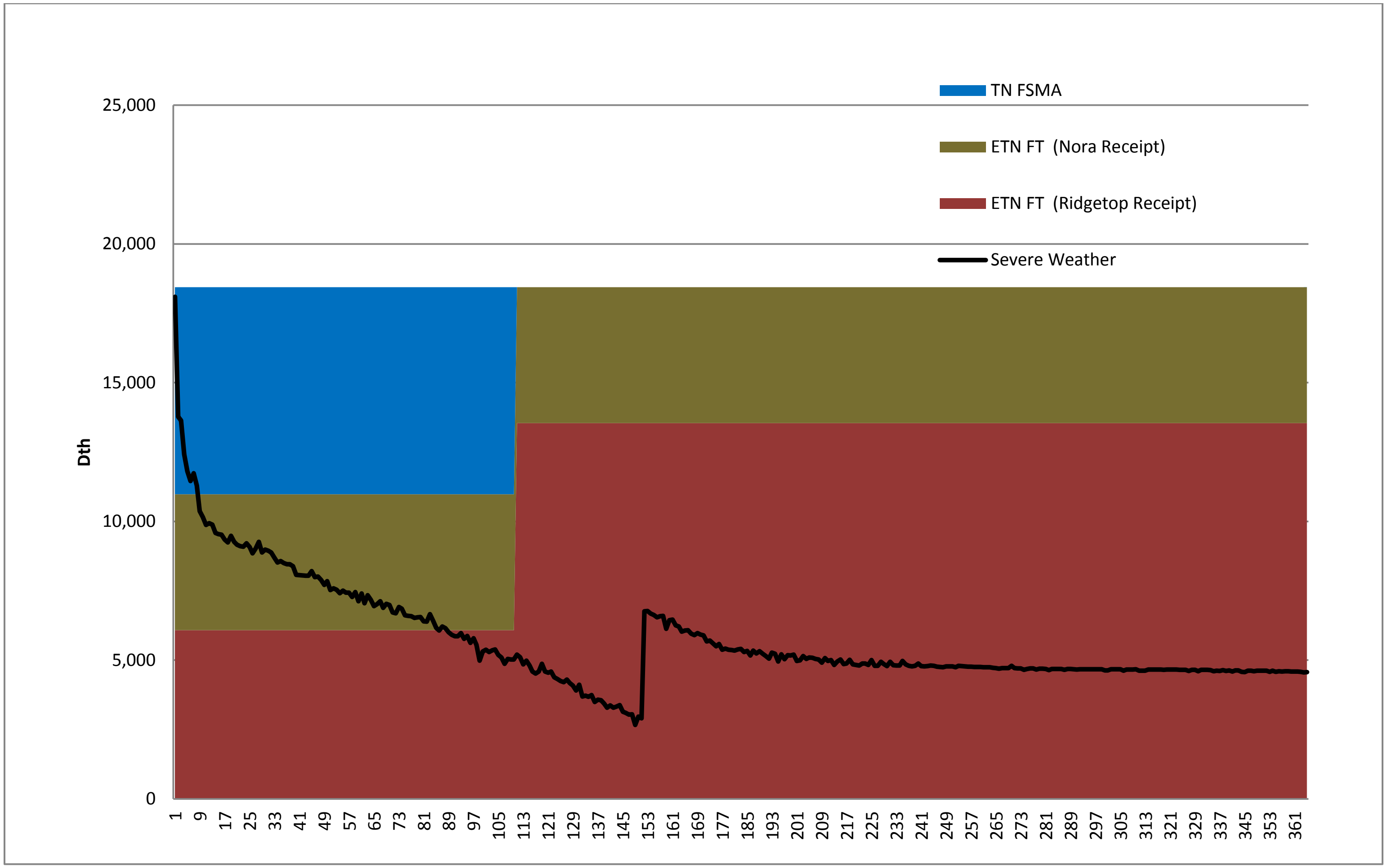


Figure 9
CHATTANOOGA GAS COMPANY
Load Duration Curve – Cleveland Service Territory



winter in which severe weather conditions are experienced, it would be expected that CGC would require use of approximately 50 percent of its maximum LNG storage inventory of 1.2 million Dth. CGC's total load requirements during a winter in which severe weather conditions are experienced is projected to be 7.65 million Dth. As shown previously in Table 1, CGC's winter season capacity resources total 11.6 million Dth. CGC's total load requirements during a year in which severe weather conditions are experienced is projected to be 9.25 million Dth, plus approximately 3.8 million Dth that may be required to fill its contract storage services and its LNG facility during the summer. As shown in Table 1, CGC's annual capacity resources total over 26 million Dth. The potential for CGC to adjust its capacity resources to better match its load requirements is addressed in the next section of the Report.

5.4 Capacity Portfolio Modifications

The RFP scope of work for Exeter's review included examination and identification of: (1) the total fixed cost of CGC's year-round firm transportation capacity to meet design day demand; (2) the total fixed cost of available seasonal firm transportation; and (3) the availability of seasonal firm transportation capacity. Exeter interprets this aspect of the scope of work as requiring an evaluation of whether CGC's annual interstate pipeline demand charges can be reduced by modifying the Company's current capacity portfolio.

The charges associated with each interstate pipeline firm transportation service purchased by CGC at the conclusion of the review period are summarized on Table 13. As shown, these charges currently total $11.2 million per year. As indicated in the previous section of the Report, CGC maintains excess year-round firm capacity. If available, the Company could reduce its demand costs by decreasing its year-round capacity and placing greater reliance on winter season capacity and/or citygate peaking supply services. With respect to citygate peaking supply services, as noted in Sections 2.3.1 and 2.3.2 of the Report, CGC has issued RFPs to secure such services, but has generally been unsuccessful in securing such services.

Table 13. CHATTANOOGA GAS COMPANY Summary of Interstate Pipeline Firm Transportation Charges			
Pipeline Service/Contract	MDQ (Dth)	Monthly Demand Charge ($/Dth)	Annual Demand Cost
TGP			
FT-A (48082)	37,819	$9.0667	$4,114,722
ETNG			
FT-A (410203)	13,000	6.67	1,040,520
FT-A (410204)	28,350	6.67	2,269,134
SONAT			
FT (FSNG130)	13,221	11.37	1,803,873
FT-NN (FSNG130)	14,346	11.37	1,957,368
Total:			**$11,185,617**

Replacing year-round capacity arrangements with winter season arrangements could also reduce CGC's annual demand charges. CGC received a proposal from SONAT in response to the RFP for peaking services for the winter of 2013-2014. However, this service was only available for one winter season, and SONAT did not submit a similar proposal in response to CGC's RFP for the winter of 2014-2015. Capacity on TGP and ETNG is fully subscribed and, therefore, winter season capacity would be unavailable and neither pipeline has offered such services. Any decrease in the reliance on annual firm transportation capacity and/or increase in the reliance on winter season arrangements is likely to reduce the revenues CGC would receive under future AMAs. Revenues under CGC's AMA would decline because less capacity would be available for optimization by the Asset Manager.

As previously shown in Table 1, the Company's year-round firm transportation service contract with TGP expires in 2020. CGC's contracts with ETNG will expire in 2018 and 2020, and its contracts with SONAT expire in 2018. Each of these contracts has a one-year notice requirement for cancellation or potential modification.

6.0 FINDINGS OF FACT AND AREAS OF CONCERN

Exeter's review period findings of fact are as follows:

- CGC contracted for services with Tennessee Gas Pipeline, East Tennessee Natural Gas, and Southern Natural Gas Company during the review period.
- During the review period, CGC operated under Asset Management Agreements with its affiliate, Sequent Energy Management, which were approved by the TRA.
- CGC served an average of 63,500 sales and transportation customers during the review period, and annual throughput averaged approximately 15 million Dth.
- CGC's storage inventory planning criteria were reasonable, CGC generally adhered to those criteria, and CGC's review period storage activity was reasonable.
- CGC realized net margins of $2,332,971 from its off-system LNG sales activities during the period April 1, 2013 – March 31, 2016, 50 percent of which was shared with ratepayers.
- CGC's design day probability of occurrence is consistent with observed industry practice.
- CGC's review period forecasts of design day demands were reasonable.
- Customer conservation efforts did not have a significant impact on design day demands.
- CGC's review period use of a 5 percent reserve margin, when viewed in conjunction with its design day criteria of 57 heating degree days, was reasonable.
- CGC could reduce its interstate pipeline demand costs by decreasing its year-round capacity and instead rely on winter season capacity; however, there are currently no opportunities for the Company to do so.
- Under the PBRM, if CGC's total actual commodity gas costs for a Plan Year do not exceed benchmark costs by one percent, the Company's gas costs are deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05(1)(a) is waived. CGC's actual gas costs during the Plan Years ended June 30, 2014 and June 30, 2015 did not exceed

benchmark costs by one percent, while actual gas costs exceeded benchmark costs by more than 3 percent during the Plan Year ended June 30, 2016.

- Exeter's review found that CGC's gas costs during the review period were prudently incurred, including the gas costs incurred during the Plan Year ended June 30, 2016.

- CGC is appropriately monitoring, evaluating, and investigating opportunities to reduce its gas costs by finding an alternative to its ETNG Nora Lateral receipt point capacity and securing TGP receipt point capacity that would provide access to lower-cost Marcellus Shale region gas supplies.

- Daily spot market purchases made to fill CGC's Nora Lateral capacity should be benchmarked based on Transco Zone 5 delivered South index prices.

- An appropriate benchmark that evaluates the prudence of CGC's monthly baseload Nora Lateral purchases cannot be reasonably established under the PBRM. To address the prudence of CGC's monthly baseload Nora Lateral purchases, Exeter recommends that these purchases be excluded from the PBRM, and that CGC be required to report to the Commission on an annual basis its efforts to reduce the costs associated with Nora Lateral monthly baseload purchases. CGC should file these reports with its annual PBRM filings. Based on these annual reports, the Commission can determine an appropriate course of action.

Exeter's review noted the following areas of concern with the Performance Based Ratemaking Mechanism during the review period:

- The RFP issued by CGC for asset management services includes a provision that requires the Asset Manager to identify, if requested by CGC, the net margins associated with the services provided to CGC. In an AMA with Sequent in place prior to the review period, the net margins associated with services provided to CGC were subject to sharing with the Company if they exceeded a pre-determined threshold. Under the current AMA, the net margins realized by the Asset Manager are no longer subject to sharing, and the requirement for an Asset Manager to disclose its net margins is typically not found in an AMA with an unaffiliated entity. The RFP provision requiring the Asset Manager to identify net margins may reduce bidder interest in an AMA RFP, and elimination of this provision should be considered.

- The spot market delivered-to-citygate purchases made by CGC from Sequent during the period February 21-23, 2015 were benchmarked by CGC under the PBRM based on Transco Zone 5 index prices. These purchases were not sourced from Transco Zone 5 and, therefore, should not have been benchmarked based on Transco Zone 5 index prices. These supplies were delivered to an ETNG meter and the source of the gas for these citygate purchases was not explicitly known. When the source of the gas is not known, the PBRM benchmark should be based on the citygate meter at which the supplies were delivered. For ETNG citygate meters, an appropriate benchmark to use would be TGP Zone L 500 Leg index prices adjusted for the applicable variable transportation charges because these purchases would have been delivered to CGC by ETNG and TGP. For SONAT citygate meters, an appropriate benchmark would be SONAT Louisiana index prices adjusted for the applicable variable transportation charges. Using TGP Zone L 500 Leg index prices to benchmark the citygate purchases made during the period February 21-23, 2015, would have decreased the negative difference between benchmark and actual costs for the Plan Year ended June 30, 2015 by approximately $180,000. However, even with this reduction, CGC's actual costs for that Plan Year would have remained below benchmark costs.

- The benchmark used for SONAT purchases injected into storage included the variable transportation charges associated with delivering gas to storage. However, the variable charges are not included in the actual cost of gas charged to CGC by Sequent that is compared to the benchmark. These variable charges are paid directly to SONAT by CGC. The impact on CGC's performance under the PBRM was not materially affected by the inclusion of the SONAT variable costs in the benchmark. Nevertheless, Exeter finds inclusion of these costs in the benchmark to be unreasonable because it does not provide for a proper comparison of actual and benchmark costs. Exeter recommends that any variable charges paid by CGC directly to an interstate pipeline should not be included in the Company's benchmark calculations.

- In January and February 2014, 89,850 Dth of LNG was transferred by truck from CGC's LNG facility to the Cherokee LNG facility of CGC's affiliate, Atlanta Gas Light. This gas was repaid in-kind by AGL in May 2014. Utility mutual aid transactions are not common among gas utilities. However, when aid is provided, it should be done so in a manner that does not negatively affect the customers of the utility that is providing the assistance. When LNG was transferred to AGL by CGC, the market price of natural gas was higher than the market price when the gas was returned to CGC. Exeter estimates the difference in market value to be approximately $114,300. Exeter recommends that for future mutual aid transactions, compensation should be based on the economic value of the transaction, and not simply a return in-kind of the volume of gas that was supplied. Exeter defers to the TRA as to whether an adjustment to CGC's gas costs is warranted for the review period.

APPENDIX A

PERFORMANCE BASED RATEMAKING MECHANISM

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO.1 REVISED SHEET56

PERFORMANCE-BASED RATEMAKING

APPLICABILITY

This Performance-Based Ratemaking Mechanism (PBRM) is designed to encourage the utility to maximize its gas purchasing activities at minimum cost consistent with efficient operations and service reliability. Each plan year will begin July 1. The annual provision and filings herein will apply to this annual period. The PBRM will continue until it is either (a) terminated at the end of a plan year or by not less than 90 days notice by the Company to the Authority or (b) modified, amended or terminated by the Authority.

OVERVIEW OF STRUCTURE

The Performance-Based Ratemaking Mechanism establishes predefined monthly benchmark indexes to which the Company's commodity cost is compared.

BENCHMARK INDEX

Each month, Chattanooga Gas Company (Company / Chattanooga) will compare its actual commodity cost of gas to the appropriate benchmark amount. The benchmark gas cost will be computed by multiplying actual purchase quantities for the month, including quantities purchased for injection into storage, by the appropriate benchmark price index.

Spot Market Purchases:

The monthly spot market benchmark is the "Index" price published in the first issue of the delivery month of *Inside FERC's Gas Market Report* in the table titled "Price of Spot Gas Delivered to Pipelines," denoted in the column labeled "Index" and the row for the applicable "Pricing Point."

Swing Purchases

For swing purchases, the benchmark " Index" price for gas delivered on any day upon which *Gas Daily* is published, is equal to the Gas Daily-Midpoint price for the immediately following day under the heading "Daily Price Survey." For gas delivered on Saturday, Sunday, or any other day upon which *Gas Daily* is not published, the price index is equal to the Daily-Midpoint for the nearest subsequent day published by *Gas Daily.*

Long-term purchases

For long term purchases, i.e., a term more than one month, the "Index" price published in the first issue of the delivery month of *Inside FERC's Gas Market Report* in the table titled "Price of Spot Gas Delivered to Pipelines" denoted in the column labeled "Index" and the row for the applicable "Pricing Point" will be adjusted for the Company's rolling three-year average premium paid to ensure long-term supply availability during peak periods.

City Gate Purchases

For city gate purchases where gas is delivered by the supplier to the local distribution company, the indexes will be adjusted for the avoided transportation costs that would have been paid if the upstream capacity were purchased versus the demand charges actually paid to the supplier.

ISSUED: OCTOBER 11, 2004 EFFECTIVE: OCTBER 1, 2004
ISSUED BY: STEVE LINDSEY, VP

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1 SECOND REVISED SHEET NO.56A

PERFORMANCE-BASED RATEMAKING
(Continued)

PRUDENCE DETERMINATION

If Chattanooga's total commodity gas cost for the plan year does not exceed the total benchmark amount by one percentage point (1%) for a plan year ending after June 30, 2000, Chattanooga's gas cost will be deemed prudent and the audit required by Tennessee Regulatory Authority's Administrative Rule 1220-4-7-. 05 is waived. If during any month of the plan year, the Company's commodity gas cost exceeds the benchmark amount by greater than two percentage points (2%), the Company shall file a report with the Authority fully explaining why the cost exceeded the benchmark.

FILING WITH THE AUTHORITY

The Company will file an annual report not later than 60 days following the end of each plan year identifying the actual cost of gas purchased and the applicable index for each month of the plan year.

Unless the Authority provides written notification to the Company within 180 days of such reports, the annual filing shall be deemed in compliance with the provisions of this Service Schedule.

PERIODIC INDEX REVISIONS

Because of changes in the natural gas marketplace, the price indices used by Chattanooga and the composition of Chattanooga's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Authority. Unless the Authority provides written notice to Chattanooga within 30 days of the Company's notice to the Authority, the price indices shall be deemed approved as proposed by the Company.

AFFILIATE TRANSACTION GUIDELINES

Terms used in these affiliate transaction guidelines have the following meanings:

1. Affiliate, when used in reference to any person in this standard, means another entity who controls, is controlled by, or is under common control with, the first entity.

2. Control (including the terms "controlling", "controlled by", and "under common control with") as used in the affiliate transaction guidelines, includes, but is not limited to, the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct or cause the direction of the management or policies of an entity. Under all circumstances, beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity shall be deemed to confer control for purposes of these affiliate transaction guidelines.

3. Gas supplier is any person who sells or otherwise provides gas to the Company. It does not include customers who transport their gas and as a result of an imbalance in the amount consumed and the amount delivered to the city gate sell gas to the Company in compliance with the Company's approved tariff provisions.

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1

REVISED SHEET NO.56C

PERFORMANCE-BASED RATEMAKING
(Continued)

Standards of Conduct

The Company must conduct its business to conform to the following standards:

1. All purchases from an affiliated gas supplier of gas for system supply or storage shall be at the price and in accordance with the terms provided in a fully executed contract between the Company and the affiliated gas supplier.

2. The Company and the affiliated gas supplier shall maintain records to show that such purchases are not at a price greater than the market price at the time of the transaction.

3. All sales of gas by the Company to an affiliated gas supplier shall be in accordance with the provisions of the Company's approved tariff or at the price and in accordance with the terms provided in a fully executed contract between the Company and the affiliated gas supplier. Any sale of gas to an affiliate not in accordance with an approved tariff provision shall be at a price that is not less than the greater of the cost as recorded on the Company's books or the market price at the time of the transaction.

4. The Company shall maintain records to show that sales to an affiliated supplier are in accordance with the applicable tariff provision or, if not provided under an approved tariff provision, the price is not less than the greater of the cost as recorded on the Company's books or market price at the time of the transaction.

5. An affiliated gas supplier shall not make sales to any customer's premise that is connected to the Company's distribution facilities.

6. The Company shall not disclose to any affiliated gas supplier any information that the Company receives from a non-affiliated gas supplier that the non-affiliated gas supplier has identified as confidential unless the prior consent of the parties to which the information relates has been voluntarily given.

7. To the maximum extent practicable, the Company's operating employees and the operating employees of an affiliated gas supplier must function independently of each other.

8. The Company must maintain its books of accounts and records separately from those of an affiliated gas supplier.

9. The Company shall maintain sufficiently detailed records of all transactions with any affiliated gas supplier.

<u>RFP PROCEDURES FOR SELECTION OF ASSET MANAGER AND/OR GAS PROVIDER</u>

1. In each instance in which Chattanooga Gas Company (Company) intends to engage the services of an asset manager to provide system gas supply requirements and/or manage its assets regulated by the Tennessee Regulatory Authority (TRA), the Company shall develop a written request for proposal (RFP) defining the Company's assets to be managed and detailing the Company's minimum service requirements. The RFP shall also describe the content requirements of the bid proposals and shall include procedures for submission and evaluation of the bid proposals.

2. The RFP shall be advertised for a minimum period of thirty (30) days through a systematic notification process that includes, at a minimum, contacting potential asset managers, including past bidders and other approved asset managers, and publication in trade journals as reasonably available. This thirty (30)-day minimum period may be shortened with the written consent of the TRA Staff to a period of not less than fifteen (15) days.

3. The procedures for submission of bid proposals shall require all initial and follow-up bid proposals to be submitted in writing on or before a designated proposal deadline. The Company shall not accept initial or follow-up bid proposals that are not written, or that are submitted after the designated proposal deadline.

ISSUED: JULY 17, 2006
EFFECTIVE: SEPTEMBER 1, 2006
ISSUED BY: STEVE LINDSEY, VP

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. 1 REVISED SHEET NO.56C

PERFORMANCE-BASED RATEMAKING
(Continued)

Following receipt of initial bid proposals, and on a non-discriminatory basis, the Company may solicit follow-up bid proposals from those submitting initial bid proposals in an effort to obtain the most overall value for the transaction.

4. All initial and follow-up bid proposals shall be evaluated as they are received. The criteria for choosing the winning bid proposal shall include, at a minimum, the following: (a) the total value of the bid proposal; (b) the bidder's ability to perform the RFP requirements; (c) the bidder's asset management qualifications and experience; and (d) the bidder's financial stability and strength. The winning bid proposal shall be the one with the best combination of attributes based on the evaluation criteria. If, however, the winning bid proposal is lower in amount than any other initial or follow-up bid proposal(s), the Company shall explain in writing to the TRA why it rejected each higher bid proposal in favor of the lower winning bid proposal. The Company shall maintain records demonstrating its compliance with the evaluation and selection procedures.

5. An incumbent asset manager shall not be granted an automatic right to match a winning bid proposal. If the incumbent asset manager desires to continue its asset management relationship with the Company after expiration of its asset management agreement, it shall submit a written bid proposal in accordance with the Company's RFP procedures. The bid proposal shall be evaluated pursuant to the procedures set forth in paragraph 4 above.

6. The Company may develop additional procedures for asset management selection as it deems necessary and appropriate so long as such procedures are consistent with the agreed-upon procedures described herein.

7. The Company shall retain all RFP documents and records for at least four (4) years and such documents and records shall be subject to the review and examination of the TRA Staff. The Asset Manager shall maintain documents and records of all transaction that utilize the Company's gas supply assets. All documents and records of such transactions shall be retained for two years after termination of the agreement and shall be subject to review and examination by the Company and the TRA Staff.