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February 23, 2010

VIA HAND DELIVERY

Chairman Sara Kyle
c/o Ms. Sharla Dillon
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

filed electronically in docket office on 02/23/10

Re: ***Review of Nashville Gas Company's IPA Relating to Asset Management Fees***
Docket No. 05-00165

Dear Chairman Kyle:

Enclosed please find an original and five (5) copies of the public version of the Review of Performance Incentive Plan and Capacity Resources, prepared in compliance with the Settlement Agreement dated February 14, 2007. Filed along with this is a confidential version, submitted under seal.

Please stamp one copy of the document as "filed" and return it to me by way of our courier.

Should you have any questions concerning any of the enclosed, please do not hesitate to contact me.

With kindest regards, I remain

Very truly yours,

R. D. Grimes

R. Dale Grimes

RDG/smb

Enclosures

8448297.1

PUBLIC VERSION
REDACTED

CONFIDENTIAL

Final Report

PIEDMONT NATURAL GAS COMPANY

AUDIT STAFF OF THE TENNESSEE REGULATORY AUTHORITY

CONSUMER ADVOCATE DIVISION OF THE TENNESSEE ATTORNEY GENERAL

REVIEW OF PERFORMANCE INCENTIVE PLAN

AND CAPACITY RESOURCES

FEBRUARY 2010

PREPARED BY:

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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PIEDMONT NATURAL GAS COMPANY

Review of Performance Incentive Plan and Capacity Resources

1.0 INTRODUCTION

On May 31, 1996, the Tennessee Public Service Commission ("Commission"), the predecessor to the Tennessee Regulatory Authority ("TRA"), issued an Order in Docket No. 96-00805 approving a gas cost Performance Incentive Plan ("the Plan") for Nashville Gas Company, predecessor to Piedmont Natural Gas Company ("Piedmont"). Since its inception in 1996, the Plan has been reviewed and modified on several occasions. Most recently, the Plan was reviewed in Docket No. 05-00165. In that proceeding, Piedmont, the Audit Staff of the TRA ("Staff"), and the Consumer Advocate Division of the Tennessee Attorney General ("CAD") (collectively "Settling Parties") filed a Settlement Agreement ("2005 Settlement") which was approved by the TRA effective July 1, 2006,

The 2005 Settlement, among other things, provides for an independent review by a consultant of Piedmont's activities under the Plan. The purpose of the independent review is to evaluate and report on all transactions and activities under the Plan conducted by Piedmont or its affiliates including, but not limited to: (a) natural gas procurement; (b) capacity management; (c) storage; (d) hedging; (e) reserve margins; and (f) off-system sales. Exeter Associates, Inc. was selected through an RFP process by the Settling Parties to perform the independent review envisioned under the 2005 Settlement. The period subject to review is July 1, 2006 through June 30, 2008 ("review period").

A Draft Report presenting the findings, results and conclusions of Exeter's review was provided to the Settling Parties on October 5, 2009. On November 12, 2009, Piedmont provided the Settling Parties and Exeter its comments on the Draft Report. Piedmont's comments were intended to clarify certain facts regarding its Performance Incentive Plan and capacity resource activities as well as respond to several findings set forth in the Draft Report. On January 15, 2010, the Settling Parties requested that Exeter incorporate Piedmont's comments into a Final Report, and to respond to Piedmont's comments as Exeter deemed appropriate. This Final Report reflects the findings set forth in the Draft Report, incorporates the comments of Piedmont and presents Exeter's response to Piedmont's comments as appropriate.

Our Final Report consists of five sections in addition to this introductory section. Section 2 of our Final Report identifies the interstate pipeline transmission companies serving Piedmont as well as the services the Company purchases from each pipeline. Section 2 also provides a description of the Piedmont 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 our Final Report summarizes each component of the Plan and summarizes and reviews Piedmont's performance by component. These include the commodity procurement cost, gas supply reservation fee, off-system sales and capacity management components of the Plan.

The fourth section of our Final Report reviews and examines the design peak day, winter season, and annual capacity resources available to meet customer demands, assesses the manner in which Piedmont forecasts the design peak day, winter season and annual demands of its customers, and evaluates whether Piedmont maintains a reasonable balance between capacity resources and the anticipated demands of its customers. This section also evaluates the design peak day criteria selected by Piedmont for capacity planning purposes and identifies actual winter season peak day demands experienced during the review period. This section concludes with a discussion of the various commodity, or variable, charges incurred by Piedmont from its interstate pipeline service providers and the collection of these costs from customers.

The fifth section of our Final Report summarizes and evaluates Piedmont's hedging activities. The final section of our Final Report summarizes our conclusions, includes findings of fact, and identifies and describes areas of concern and improvement, which may warrant further consideration.

2.0 PIEDMONT SYSTEM AND MARKETS

Piedmont provides natural gas sales and distribution service to the Nashville, Tennessee metropolitan area. Piedmont purchased services from five interstate pipelines during the review period: Columbia Gas Transmission ("Columbia Gas"), Columbia Gulf Transmission ("Columbia Gulf"), Midwestern Gas Transmission ("Midwestern"), Tennessee Gas Pipeline ("Tennessee Gas") and Texas Eastern Transmission ("Texas Eastern"). Of these five interstate pipelines, Piedmont is interconnected with three: Columbia Gulf, Tennessee Gas and Texas Eastern. These interconnects are summarized in Table 1. The interstate pipeline services purchased by Piedmont during the review period are summarized in Table 2 and are described in the following section. This information is provided to assist in understanding the various components of the Plan and in evaluating Piedmont's capacity resources.

2.1 Interstate Pipeline Transportation Services

Piedmont's transportation arrangements with Columbia Gulf, Tennessee Gas and Texas Eastern provide for the delivery of gas supplies directly to Piedmont's system. As subsequently explained, although Piedmont is not directly interconnected with Columbia Gas, Piedmont's transportation arrangement with Columbia Gas provides for the delivery of gas supplies directly to Piedmont's system. Piedmont's transportation arrangement with Midwestern provides for the delivery of gas from the Chicago market area to Tennessee Gas and Columbia Gulf, but not directly to Piedmont's system. Midwestern-sourced gas supplies are delivered from Midwestern to the west side of Piedmont's system by Tennessee Gas and to the east side by Columbia Gulf.

Table 1

PIEDMONT NATURAL GAS COMPANY
Summary of Interstate Pipeline Interconnects

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 2

PIEDMONT NATURAL GAS COMPANY
Summary of Capacity Resources
(Dth)

CITYGATE RESOURCES

Pipeline - Service	Contract No.	MDQ Winter	MDQ Summer	Winter Season	Annual	Upstream Resource	Contract Expiration
Columbia Gas							
Storage Service (FSS/SST)	38017 (FSS) 38052 (SST)	10,000	5,000	611,870	0	None	10/31/2010
Columbia Gulf							
Firm Transportation (FTS-1)	76812	5,000	5,000	755,000	1,825,000	None	03/31/2013
Firm Transportation (FTS-1)	43462	5,000	4,601	755,000	1,739,614	None	03/31/2010
Firm Transportation (FTS-1)	Segment	10,000	10,000	1,510,000	3,650,000	Midwestern	Various
Interruptible Transportation (ITS-1)	-----------	43,000	43,000	6,493,000	15,695,000	Midwestern	
Tennessee Gas							
Firm Transportation (FT-A)	237	74,100	74,100	11,189,100	27,046,500	None	10/31/2014
Firm Transportation (FT-BH)	46715	26,000	26,000	3,926,000	9,490,000	Midwestern	10/31/2014
Firm Transportation (FT-A)	237	21,000	21,000	3,171,000	7,665,000	Midwestern	10/31/2014
Storage Service (FT-BH/FS-MA)	6815 2A	49,828	49,828	2,901,943	0	None	04/30/2014
Storage Service (FT-BH/FS-PA)	2400 2A	6,072	6,072	672,091	0	None	04/30/2014
Texas Eastern							
Firm Transportation (FT-1)	910473	10,000	0	1,510,000	1,510,000	None	03/31/2019
Firm Transportation (SCT)	800059	1,677	1,677	84,409	204,035	None	10/31/2010
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]					

UPSTREAM RESOURCES

Pipeline - Service		MDQ Winter	MDQ Summer	Winter Season	Annual	Upstream Resource	Contract Expiration
Midwestern Gas							
Firm Transportation (FT-A)	FA0342	100,000	100,000	15,100,000	36,500,000	None	01/06/2023
	FB0006	100,000	100,000	15,100,000	36,500,000	FA0342	01/06/2023

2.1.1 Columbia Gas Transmission

Piedmont purchased unbundled firm storage transportation service from Columbia Gas during the review period under Rate Schedule SST. Piedmont purchases unbundled firm storage service from Columbia Gas under Rate Schedule FSS. Storage transportation service under Rate SST is utilized to transport gas to and from the storage facilities of Columbia Gas and Piedmont's system. Columbia Gas is not physically connected to the Piedmont system, and Columbia Gulf is operated as an extension of the Columbia Gas system under this arrangement. The gas delivered to Columbia Gas storage for injection is generally purchased in the Gulf Coast production region and delivered to Columbia Gas by Columbia Gulf.

2.1.2 Columbia Gulf Transmission

Piedmont purchased transportation service from Columbia Gulf under three different arrangements during the review period. Piedmont purchased firm transportation service under two contracts under Rate Schedule FTS-1 which provided for the delivery of Gulf Coast-sourced gas supplies directly to Piedmont's system. Contract No. 76812 provided for the delivery of 5,000 Dth per day year-round, while Contract No. 43462 provided for the delivery of 5,000 Dth per day during the winter period (November through March) and 4,601 Dth per day during the summer period (April through October). The capacity under Piedmont's Columbia Gulf FTS-1 arrangements can be segmented, in some circumstances, to deliver up to 10,000 Dth per day of Gulf Coast sourced supplies and at the same time up to 10,000 Dth per day of Midwestern-sourced gas supplies.

Piedmont also maintained an interruptible transportation arrangement with Columbia Gulf providing for the delivery of up to 43,000 Dth per day. This arrangement is utilized to deliver gas from Columbia Gulf's interconnect with Midwestern at Walnut Grove, Tennessee to Piedmont's system.

2.1.3 Midwestern Gas

Effective November 2007, Piedmont contracted for 20,000 Dth per day of capacity with Midwestern. This arrangement provided for the delivery of gas from the Chicago market area to Tennessee Gas at Portland, Tennessee, with final delivery effectuated to the west side of Piedmont's system by Tennessee Gas. This arrangement expired effective with the completion of Midwestern's Eastern Expansion Project.

Through its participation in Midwestern's Eastern Expansion Project, Piedmont increased its contractual capacity to 100,000 Dth per day effective with the completion of the project on January 7, 2008. The Eastern Expansion Project also allowed Midwestern to interconnect with Columbia Gulf at Walnut Grove, Tennessee. Midwestern-sourced gas supplies are delivered to the west side of Piedmont's distribution system by Tennessee Gas and the east side of Piedmont's distribution system by Columbia Gulf. Midwestern Contract No. FA0342 provides for firm transportation from the Chicago area to an interconnect with Tennessee Gas at Portland, Tennessee. Midwestern Contract FB0006 provides for firm transportation from Portland, Tennessee to an interconnect with Columbia Gulf at Walnut Grove, Tennessee.

2.1.4 Tennessee Gas Pipeline

The Tennessee Gas system originates in the Texas and Louisiana natural gas production regions and extends to New England. In the production region, the Tennessee Gas system consists of three primary transmission lines, referred to as the 100, 500 and 800 Legs. The Tennessee Gas system is also divided into 6 zones for rate purposes. Texas is designed as Zone 0, and Zone 1 extends from the Texas border with Louisiana to the Kentucky/Tennessee border. During the review period, Piedmont purchased firm transportation from Tennessee Gas under Contract No. 237 under Rate Schedule FT-A. This contract provided for the delivery of 74,100 Dth per day of Gulf Coast supplies directly to Piedmont's system. Piedmont's receipt point capacity under Contract No. 237 is subdivided by leg and zone as follows:

Zone 0 – 100 Leg:	22,435 Dth
Zone 1 – 500 Leg:	28,204 Dth
Zone 1 – 800 Leg:	23,461 Dth
Total	74,100 Dth

Tennessee Gas Contract No. 46715 is a back-haul transportation arrangement that provides for the delivery of gas from Tennessee Gas' interconnect with Midwestern at Portland, Tennessee to Piedmont's system. The effective contract quantity under Contract No. 46715 is 26,000 Dth per day.

2.1.5 Texas Eastern Transmission

Piedmont purchased firm transportation service from Texas Eastern under two different rate schedules during the review period. Piedmont purchased 10,000 Dth per day of winter season firm transportation service under Rate Schedule FT-1. Piedmont also purchased small customer firm transportation service under Rate Schedule SCT. Service under Rate Schedule SCT is a no-notice, firm transportation service. Piedmont utilizes both Texas Eastern transportation arrangements to acquire Gulf Coast sourced gas supplies. Rate Schedule SCT capacity is excluded from the subsequently discussed commodity procurement cost component of the Plan.

2.2 Interstate Pipeline and On-system Storage

Piedmont subscribed to contract storage service from Columbia Gas and Tennessee Gas during the review period. Piedmont also operates an on-system liquefied natural gas ("LNG") facility.

2.2.1 Columbia Gas Transmission

Piedmont purchased firm storage from Columbia Gas under Rate Schedule FSS during the review period. Gas is delivered to and from Columbia Gas storage under Piedmont's SST and FTS arrangement with Columbia.

2.2.2 Tennessee Gas Pipeline

Piedmont purchased bundled market area firm storage service from Tennessee Gas under Rate Schedule FS-MA and bundled production area firm storage service under FS-PA. Gas delivered to both market and production area storage is primarily sourced on Tennessee Gas and purchased in the Gulf Coast region. Deliveries to Piedmont's system from market and production area storage are nominated at Tennessee Gas' Portland, Tennessee station.

2.2.3 Liquefied Natural Gas

[redacted]

2.3 Markets Served by Piedmont

Piedmont 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 Piedmont's citygates. Table 3 summarizes the number of customers served and annual throughput by service class for 2007 and 2008.

Table 3

PIEDMONT NATURAL GAS COMPANY
Annual Customers and Volumes by Class

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

3.0 PERFORMANCE INCENTIVE PLAN

This section of our report summarizes and evaluates Piedmont's activities under the Performance Incentive Plan by component. These components include: (a) commodity procurement costs; (b) supplier reservation fees; and (c) capacity management. A complete description of the Plan is included as Appendix A to our report.

3.1 Commodity Procurement Costs

3.1.1 Background and Description

In the natural gas industry, there are generally two types of gas supply purchase arrangements – first-of-the-month monthly baseload ("first-of-the-month," or "FOM") purchases and daily ("spot market") purchases. FOM 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. Spot market purchases are generally arranged the day prior to delivery. While spot market purchases generally flow for one day, spot market purchases may also be arranged for multiple days.

There are various natural gas industry publications which identify, after the fact, the average price paid for purchases of FOM and spot purchases at major natural gas trading locations. These average prices are referred to as index prices.

Under the commodity procurement cost component of the Plan, Piedmont's actual total monthly citygate (delivered) commodity cost of gas is compared to a monthly benchmark cost amount. The actual total citygate commodity cost of gas

includes the amount paid for gas supply commodity purchases, plus the applicable pipeline fuel and variable transportation charges associated with delivering gas from the purchase (receipt) point to Piedmont's system. If Piedmont's actual monthly costs exceed benchmark costs, 25 percent of the difference is assessed to Piedmont, and sales customers' gas costs are reduced by the amount assessed to Piedmont.
If benchmark costs exceed actual monthly costs, 25 percent of the difference is retained by Piedmont, and sales customers' gas costs are increased by the amount retained by Piedmont.

The monthly benchmark cost amount is calculated by multiplying the actual quantity of gas delivered to Piedmont's citygate during a month by a Monthly Benchmark Index Price ("MBIP"). The MBIP includes separate cost components for FOM and spot market purchases delivered under Piedmont's firm transportation arrangements, and for purchases made at Piedmont's citygate. Each cost component is added together to derive the MBIP.

For the FOM purchase cost component of the MBIP, a delivered-to-citygate price is first calculated for each geographic receipt point location accessed by Piedmont's firm transportation capacity based on the applicable monthly FOM index price and fuel and variable transportation charges. A weighted average delivered-to-citygate price is then calculated based on the amount of capacity Piedmont reserves at each receipt point location. The weighted average price is then multiplied by the percentage derived by dividing FOM purchases by total monthly purchases.

The spot market purchase cost component of the MBIP is determined by first pricing each of Piedmont's actual spot market purchases at the applicable daily index price, and then adding the applicable fuel and variable transportation charges. The delivered costs for each purchase are totaled and divided by the actual monthly quantity of spot market purchases to arrive at an average price, which is then multiplied by the percentage derived by dividing total monthly spot purchases by total monthly purchases.

The citygate cost component of the MBIP is calculated in the same manner as the spot market purchases component with the exception that maximum interruptible pipeline transportation charges are utilized rather than variable charges. Shown in Table 4 for illustrative purposes are the calculations of the MBIP for February 2007 and February 2008. These two monthly were selected because they are representative of Piedmont's pre- and post-Midwestern Eastern Expansion Project capacity portfolios.

3.1.2 Results and Conclusions

The relationship between delivered prices for gas at the various receipt point locations Piedmont purchases gas can vary over time. For example, as shown on Table 5, Tennessee Gas Zone 0 sourced gas was generally Piedmont's lowest delivered cost source of supply, and Midwestern sourced supplies were at times Piedmont's lowest cost supply (e.g., August 2007), and at other times Piedmont's highest delivered cost supply (e.g., December 2007). However, an active daily participant in the natural gas market such as Piedmont would be well aware of these current price relationships. Shown on Table 6 is a summary of the rewards Piedmont

Table 4

PIEDMONT NATURAL GAS COMPANY
Sample Monthly Benchmark Index Price Calculations
(Dth)

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]				
[redacted]		[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]				
[redacted]		[redacted]	[redacted]	[redacted]

[redacted]

Table 5

PIEDMONT NATURAL GAS COMPANY
Summary of Delivered Prices by Pipeline Location
(Dth)

[redacted]

Table 6

PIEDMONT NATURAL GAS COMPANY
Summary of Natural Gas Procurement Commodity Cost Rewards by Type of Purchase

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

realized under the commodity procurement cost component of Plan by type of purchase (i.e., FOM, spot market, citygate). [redacted]

The current design of the first-of-the-month cost component of the MBIP under the Plan provides an incentive to purchase gas at receipt point locations with the lowest total delivered costs. While such an incentive is desirable, our Draft Report expressed concern that the current design provides rewards which greatly exceed any improvement in Piedmont's commodity cost procurement performance. Piedmont is simply utilizing price intelligence that all market participants have available to decide at which receipt point locations to purchase gas and then paying index prices for gas. That is, they are paying average market prices for gas. It is Exeter's conclusion that the Plan provides rewards for performance which is not superior to that of other market participants. The spot market and citygate purchase cost components of the MBIP only result in rewards if Piedmont is able to acquire gas at below average market prices.

[redacted]

Table 7

PIEDMONT NATURAL GAS COMPANY
Illustration of March 2008 Commodity Cost Reward
(Dth)

	[redacted]		[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]

In its response to Exeter's Draft Report, Piedmont indicated that the intended goal of the Plan was not to provide rewards only when the Company out-performed other market participants. Piedmont claims that the goal of the Plan was to align the interests of Piedmont and its customers with respect to procuring and selecting the lowest delivered cost of gas available.

Exeter did not participate in Docket No. 05-00165, the proceeding in which the current Plan was last reviewed, nor was it a party to the proceeding in which the Plan was initially approved. Therefore, Exeter cannot comment on the intent or goal of the Plan. Nevertheless, it remains Exeter conclusion that, based on its extensive experience in the auditing of utility gas purchasing practices, the first-of-the-month cost component of the MBIP results in rewards which we believe to be excessive. That is, much of the "savings" under this aspect of the Plan would be realized without the existence of the Plan.

3.2 Supplier Reservation Fees

[redacted]

3.2.2 Results and Conclusions

Gas supply contracts can be arranged to provide for a discount to commodity index prices in exchange for higher demand charge reservation fees. The Plan requires modifications to the applicable index price to reflect such discounts. Gas supply contracts can also be arranged which provide for the ability to purchase gas at first-of-the-month index prices after the first-of-the-month when spot market gas prices are higher (FOM call option) in exchange for higher demand charge fees. With 100 percent recovery of supplier reservation fees, FOM call option contracts could improperly reward

Piedmont. All of Piedmont's contracts with demand charge reservation fees during the review period included index commodity pricing, with no first-of-the-month price purchase rights. In its comments, Piedmont indicated it had no intention of utilizing FOM call option gas supply contracts.

3.3 Capacity Management

Piedmont's capacity management activities during the review period included asset management arrangements, capacity release and off-system sales. Table 8 summarizes the revenues from these activities for the review period. Piedmont is entitled to retain 25 percent of the revenues derived from these activities. These sharing procedures are consistent with those adopted in other jurisdictions.

Table 8

PIEDMONT NATURAL GAS COMPANY

Summary of Capacity Management and Off-System Sales Revenues
(Dth)

			[redacted]		[redacted]	[redacted]	[redacted]
[redacted]	Capacity [redacted]	Asset [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
						[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.3.1 Asset Management Agreement

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

3.3.2 Capacity Release

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

In its comments on the Draft Report, Piedmont appears to interpret Exeter's Draft Report to suggest that the Company did something improper by including Midwestern capacity in the calculation of the Monthly Benchmark Index Price. Exeter's review found that Piedmont was in technical compliance with the terms and conditions of the Plan during the review period. Under the Plan, Midwestern capacity was to be included in the calculation of the MBIP. Therefore, Piedmont did nothing improper. Exeter's comments in the Draft Report on the Midwestern capacity relate to Exeter's overall conclusion that the MBIP provides excessive rewards.

Our Draft Report revealed a concern with the structure of the Plan with respect to capacity release. Under the first-of-the-month pricing calculation of the commodity procurement cost component of the Plan, capacity which has been released is removed from the weightings applied to the first-of-the-month delivered prices to determine the market benchmark index price. This gives Piedmont the incentive not to release unutilized capacity which would have a high delivered cost of gas. For example, in April, May and June of 2008, gas sourced on Columbia Gulf was Piedmont's highest cost supply, none of the capacity was used by Piedmont for system supply and none of the Columbia Gas capacity was released.

In its comments, Piedmont acknowledged that the Plan could potentially result in opportunities to "game" the manner in which Piedmont conducts capacity release transactions by not releasing capacity associated with more expensive gas supply sources. Piedmont claimed that it does not engage in such gaming and instead attempts to release upstream assets at the best possible price when those assets are not needed to serve Piedmont's core customers. Exeter clarifies that it did not find that Piedmont engaged in such gaming during the review period.

3.3.3 Off-System Sales

[redacted] [redacted]

[redacted]

[redacted]

b) Results and Conclusions

Our Draft Report identified several concerns with Piedmont's administration of its off-system sales program is under the Plan. These concerns were revealed by examining activities during March and April 2008, the months with the highest amount of off-system sale activity. During each of these months, gas prices rose steadily, and Piedmont claimed to be in an excess gas supply situation. Because of the rising prices, Piedmont was able to sell gas supplies it had purchased at first-of-the-month prices at a profit with little difficulty.

One initial concern with Piedmont's off-system sales activities during March and April 2008 was that the evidence did not support Piedmont's contention that it was in an excess supply situation. On a number of occasions during these months, Piedmont sold gas off-system only to purchase additional spot market supplies the next day. Given the flexibility associated with the storage services purchased by Piedmont, it appeared that it was unnecessary for Piedmont to have sold all of the gas it sold off-system. Because the spot purchases made by Piedmont were at prices in excess of the supplies sold off-system, sales customers appeared to have been adversely affected by Piedmont's off-system sales activities during these months.

In its comments on Exeter's concern with respect to selling gas off-system one day and then making spot purchases on the next, Piedmont presented additional evidence to support the reasonableness of its off-system sales activities. Based on our review of the additional evidence, Piedmont has satisfied Exeter's concerns with respect to this aspect of Piedmont's March and April 2008 off-system sales activities.

A remaining concern with the administration of Piedmont's off-system sales activities which is highlighted by the Company's activities during March and April 2008 relates to the supplies it selected to sell off-system. For example, in April 2008, all of the gas sold off-system were Tennessee Gas Zone 0 sourced supplies. This was Piedmont's cheapest source of supply, thus, the off-system sale of this gas maximized benefits for Piedmont, but not necessarily sales customers. The benefit to sales customers would have been maximized if Piedmont sold its highest cost gas supplies off-system. In other jurisdictions, when a gas utility is in an excess supply situation, a weighted average cost of gas is assigned to supplies sold off-system. However, more commonly, specific spot market purchases are made to support off-system sales, thereby eliminating the need to determine which current supplies should be sold off-system.

4.0 EVALUATION OF CAPACITY PORTFOLIO AND IDENTIFICATION OF VARIABLE CHARGES

4.1 Design Peak Day Forecast

Piedmont attempts to secure sufficient capacity resources to meet the forecasted design peak day requirements of sales customers and those transportation customers which select standby service. Piedmont's design peak day forecast calculation involves several steps. First, actual throughput and heating degree days experienced on the most recent day that approached Piedmont's design peak day temperature criteria are determined. [redacted] Next, interruptible usage is removed from total throughput to determine firm requirements. Actual firm requirements are then increased by usage per heating degree day factors to estimate what firm requirements would have been under design peak day conditions. This total is adjusted for firm customer growth actually experienced or expected to be experienced between the most recently observed near design peak day [redacted] and the year for which a forecast is being prepared. Finally, a [redacted] percent reserve margin is added to the total forecast quantity and firm transportation customer usage is removed to determine Piedmont's capacity requirements.

From Exeter's experience, Piedmont's design peak day forecasting approach is not consistent with generally observed industry practices. Gas utilities typically develop design peak day forecasts using regression analysis of actual daily firm sendout and independent variables such as daily heating degree days, day of the week and average daily wind speed. Exeter prepared an independent analysis of Piedmont's design peak day firm requirements, exclusive of the [redacted] percent reserve margin, utilizing an approach more commonly used by gas utilities. That is, Exeter prepared a forecast utilizing a linear regression model which estimated firm sendout as a function of heating degree days, day of the week and average daily windspeed. Exeter utilized data for the most recent three-year winter period to prepare its forecast. Piedmont's forecast and Exeter's independent forecast compare as follows for the 2009 – 2010 winter season:

[redacted]

[redacted] [redacted]

Based on the minimal difference between the two forecasts, Piedmont's approach does not appear to be a concern at this time. However, as the length time increases between the most recent near design peak day and the forecast period, Piedmont should consider more conventional approaches to design peak day forecasting.

Our review noted that Piedmont's design peak day forecasting approach did not explicitly consider customer conservation efforts. Because Exeter's forecasted utilized the most recent three years of data, recent customer conservation efforts are reflected in our forecast.

4.2 Design Peak Day Criteria and Reserve Margin

As previously indicated, Piedmont utilizes a day with [redacted] heating degree days for its design peak day criteria. Piedmont personnel are unaware as to how this criterion was originally selected. Since 1975, temperatures as cold or colder than Piedmont's selected design peak day criteria have been observed on six occasions, indicating an annual probability of occurrence of approximately once every 6 years. This probability of occurrence is slightly higher than that utilized by other gas utilities which range from 1-in-10 to 1-in-20 year probabilities of occurrence.

Generally, it has been Exeter's position that reserve margins are no longer reasonable for gas utilities. However, the use of a reserve margin must be considered in light of several factors, including the probability of design peak day occurrence. In this case, Piedmont's design peak day capacity requirements are approximately equal to selecting a design peak day of [redacted] heating degree days and maintaining a [redacted] percent reserve margin, with selecting a design peak day of [redacted] heating degree days and maintaining no reserve margin. Given the heating degree days observed in its service territory since 1975, the use of [redacted] heating degree days as Piedmont's design peak day criteria would not be considered unreasonable. Therefore, Piedmont's selection of a [redacted] heating degree day as its design peak day and maintaining a [redacted] percent reserve margin cannot be considered unreasonable.

4.3 Actual Peak Day

Table 9 summarizes the sendout of sales customers on the actual peak day observed during each winter season of the review period. Also shown are actual heating degree days. Because each actual peak day was considerably warmer than Piedmont's [redacted] heating degree day design peak day, the sendout of sales customers was significantly less than the forecasted sendout of sales customers on design peak day.

Table 9

PIEDMONT NATURAL GAS COMPANY
Summary of Actual Peak Day Sales Sendout
(Dth)

[redacted]	[redacted]	[redacted]	
		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

4.4 Balance of Capacity Resources and Design Peak Day Requirements

As initially shown on Table 2, the capacity resources available to meet Piedmont's design peak day requirements for the 2008 – 2009 winter season totaled [redacted]. Estimated design peak day sales requirements, including the [redacted] percent reserve margin totaled [redacted], suggesting that Piedmont maintained a capacity surplus of [redacted]. The capacity surplus is directly attributable to the acquisition of 100,000 Dth of capacity as a result of the completion of Midwestern's Eastern Expansion Project. The capacity surplus is expected to be absorbed by Piedmont system load growth in approximately five years. Under current Federal Energy Regulatory Commission ("FERC") pipeline expansion procedures, it would have been necessary for Piedmont to contract or pay for the entire cost of the 100,000 Dth of capacity. The amount of capacity made available could have possibly been phased-in to coincide with Piedmont's requirements; however, the total costs associated with the expansion would have been greater and would have ultimately been the responsibility of Piedmont. Therefore, the current capacity surplus cannot be considered imprudent. In addition, Piedmont can release capacity to assist in alleviating the current capacity surplus.

4.5 Winter Season Capacity Resources and Requirements

As initially shown on Table 2, the capacity resources available to meet Piedmont's winter season requirements for the 2008 – 2009 winter season totaled 34.5 Bcf. The estimated winter season requirements of sales customers under a 15 percent colder-than-normal winter season which Piedmont utilizes for capacity planning purposes are 19.5 Bcf. Thus, from a planning perspective, Piedmont's winter season capacity resources exceed requirements by 15.0 Bcf, or approximately 75 percent. However, as previously explained in Section 3.3.2(a) of our report, Piedmont released all of its Midwestern capacity during the review period at rates which equaled its costs. [redacted] Capacity not paid for by Piedmont should be eliminated when evaluating the balance between Piedmont's winter season capacity resources and requirements. Based on actual usage of Midwestern capacity during the winter of 2007-2008, approximately 2.0 Bcf of the 15.1 of Midwestern winter season capacity available to Piedmont should be considered a capacity resource. This would reduce Piedmont's winter season capacity excess by approximately 13.0 Bcf to approximately 2.0 Bcf, or 10 percent. An excess of this magnitude would not be considered unreasonable.

4.6 Annual Capacity Resources and Requirements

Piedmont prepares annual monthly forecasts of the projected use of residential and commercial sales customers. The forecasts are prepared using two factors: (1) customer usage factors by rate schedule developed by weather normalizing the prior years' actual usage; and (2) customer growth trends using the most recent two years' actual growth adjusted to reflect any known significant changes or trends. The projections for larger accounts utilize a historical individual customer review.

The estimated requirements of Piedmont's sales customers during a year in which a service winter season is experienced are approximately 24.0 Bcf. As shown on Table 2, the capacity resources available to meet Piedmont's annual requirements total 68.8 Bcf. Based on annual requirements of 24.0 Bcf, Piedmont maintains an annual deliverability surplus of approximately 44.8 Bcf, or approximately 185 percent. However, as with an evaluation of the balance between winter season capacity resources and requirements capacity, the Midwestern capacity not paid for by Piedmont should be eliminated as a capacity resource. Based on the actual usage of Midwestern capacity during the period November 1, 2007 through June 30, 2008, approximately 3.0 Bcf of the 36.5 Bcf of Midwestern annual capacity available to Piedmont should be considered as a capacity resource. This would reduce Piedmont's annual capacity excess by approximately 33.5 Bcf to approximately 11.3 Bcf, or 45 percent. Piedmont's excess annual capacity balance is discussed further in Section 4.7 of our report.

4.7 Capacity Portfolio Modifications

[redacted]

[redacted]

[redacted]

Table 10

PIEDMONT NATURAL GAS COMPANY

Summary of Interstate Pipeline Firm Transportation Charges

(Dth)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 11

PIEDMONT NATURAL GAS COMPANY
Summary of Delivered Quantities by Pipeline Location
(Dth)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.8 Commodity, Fuel and Storage Charges

In addition to requiring the payment of demand charges which are fixed and not based on actual usage, the firm transportation services Piedmont purchases from its interstate pipelines require the payment of variable, or commodity, charges which are based on actual use. Piedmont is also assessed in-kind fuel charges based on actual purchase quantities. Under its pipeline storage arrangements, Piedmont is assessed volumetric injection and withdrawal charges, and is also assessed a storage fuel charge.

A requirement of our review was to identify and compare the various commodity costs charged to Piedmont's sales customers with those charged to Piedmont. During the course of our review, Piedmont indicated that it did not maintain information in a manner which would enable Exeter to identify the specific charges by type. However, our review revealed that Piedmont recovers the interstate pipeline commodity charges billed to it from its Tennessee sales customers on a dollar-for-dollar basis.

5.0 HEDGING ACTIVITY

5.1 Background and Description

The 2005 Settlement provided for the recovery of hedging transaction costs as a purchased gas cost, and defined hedging transactions to include futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs. Hedging transaction costs included amounts paid for financial instruments such as options, and recovery was limited to 1 percent of the Company's total annual gas costs. All hedging transaction gains and losses are reflected in the rates of sales customers.

Piedmont's hedging program is partially dependent on natural gas futures prices (as listed on the New York Mercantile Exchange "NYMEX"), and partially time dependent. The Company's forward hedging horizon during the review period was two years, and effective December 1, 2008 was reduced to one year. Piedmont hedges for the winter season only, and the 1 percent amount available for hedging is allocated equally to the five winter months.

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

A costless collar entails selling a put option which guarantees a floor price the Company would pay for its supply and uses the value received from selling the put option to purchase a call option which establishes a ceiling or maximum price the Company would pay for its supply. Purchasing an outright call option establishes a ceiling price that the Company would pay for its supply but allows the Company to participate in a downward or falling price market. A collar is similar to a costless collar except there are additional costs associated with purchasing the call above the value received for selling the put.

A call spread involves buying a call and selling a call which gives the Company some upward protection up to a predefined level. For example, purchasing a call with a strike price of $6.00 and selling a call with a strike price of $9.00 would mean that the Company would pay no more than $6.00 for gas as long as the market price didn't exceed $9.00, but would forfeit any protection if prices rose above $9.00. The purpose of this hedging strategy is to use the proceeds received from selling the $9.00 call and include it in the money available to purchase a call. This allows the Company to achieve a call with a lower strike price.

A three-way is a combination of the call spread and a collar. The Company purchases a call which gives upside, high price protection, sells a call which limits the upside protection to some established level and sells a put which establishes a floor price or lower limit to what the Company would pay for its supply. The value received for selling the put and call are added to the amount available to spend for a call and helps the Company achieve a lower strike price or earlier level of protection in the event of a price rise. The level of protection received will be limited to the strike price of the call sold. The Company would continue to participate in downside market price movement until the floor price is met. Any additional market movement below the floor price established by the sale of the put would be forfeited.

Piedmont's actual hedging activity during the review period is summarized on Table 12. Table 12 classifies Piedmont's review period hedging activity into three categories: (1) the sale and subsequent purchase of call options prior to option expiration; (2) the sale of call options which were subsequently exercised by the counter-party or which expired; and (3) the purchase of call options, all of which expired without being exercised. [redacted]

Table 12

PIEDMONT NATURAL GAS COMPANY

Summary of Hedging Activity

(Dth)

[redacted]

5.2 Results and Conclusions

The use of a partially price and partially time dependent approach to hedging is reasonable. Piedmont's use of a decile matrix to guide its purchasing decisions and the 1 percent limit on hedging transaction costs are consistent with the practices of other utilities. However, the goal of hedging is to mitigate price volatility, and our Draft Report found Piedmont's hedging program to be too small to achieve any meaningful benefit.

Most utilities which have adopted hedging programs rely heavily, and many exclusively, on forward fixed price purchases for a significant percentage of their gas supply purchases. The Company does not utilize forward fixed price purchases because those purchases would be reflected in the Performance Incentive Plan. As such, if the price of the Company's forward fixed price purchases exceeded market prices at the time of delivery, the Company would experience a loss under the Plan. Piedmont has indicated that it is unwilling to take such a risk. In other jurisdictions with incentive mechanisms similar to Piedmont's Plan, forward fixed price purchases are excluded from the incentive mechanism.

In its comments on Exeter's Draft Report, Piedmont indicated that its hedging activities are performed pursuant to the approved Plan, and acknowledge that it would be unwilling to risk incurring losses under the Plan from forward fixed price purchases. Exeter agrees that Piedmont adhered to the hedging activities approved under the Plan and understands Piedmont's unwillingness to assure the risks associated with forward fixed price purchases. Nevertheless, in Exeter's opinion, given the 1 percent limit for financial instruments and absent the use of forward fixed price purchases, Piedmont's hedging program is too small to achieve any meaningful price volatility mitigation.

6.0 FINDINGS OF FACT AND AREAS OF CONCERN

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

- Piedmont was in technical compliance with the terms and conditions of the Performance Incentive Plan during the review period;
- Piedmont served an average of 162,225 sales and transportation customers during the review period, and throughput averaged 27,980,500th;
- Piedmont increased its Midwestern Gas Transmission pipeline capacity from 20,000 Dth per day to 100,000 Dth per day effective January 7, 2008 upon completion of Midwestern's Eastern Expansion Project;
- Piedmont earned a reward of [redacted] under the Plan during the review period;
- Piedmont earned a reward of [redacted] under the commodity procurement cost component of the Plan during the review period, and this reward was realized almost exclusively on first-of-the-month priced purchases;
- All of Piedmont's gas supply contracts with supplier reservation fees during the review period included index commodity pricing with no first-of-the-month price purchase rights;
- [redacted]
- Piedmont earned a reward of [redacted] from its capacity release, asset management and off-system sales activities during the review period;
- [redacted]
- [redacted]
- Piedmont's current forecast of design peak day demands is reasonable;

- Piedmont does not incorporate customer conservation efforts in its design peak day forecast;

- Piedmont's use of a [redacted] reserve margin when viewed in conjunction with its design peak day criteria of [redacted] heating degree days is reasonable;

- The balance between Piedmont's review period winter season capacity resources and requirements was reasonable;

- Piedmont maintains excess year-round firm transportation capacity and increasing the amount of year-round capacity would only serve to increase the Company's annual pipeline demand charges;

- Piedmont could reduce its pipeline demand costs by decreasing its year-round capacity and instead rely on winter season capacity; however, the Company's opportunities to do so are limited until [redacted];

- Piedmont's use of a partially price and partially time dependent approach to hedging is reasonable; and

- Piedmont's use of a decile matrix to guide its hedging purchasing decisions and the 1 percent limit on hedging transaction costs are consistent with the practices of other utilities.

Exeter's review noted the following areas of concern with the Performance Incentive Plan during the review period:

- The current design of the first-of-the-month cost component of the Monthly Benchmark Index Price ("MBIP") results in rewards which greatly exceed any improvement in Piedmont's commodity cost procurement performance, and results in rewards for performance which is not superior to that of other market participants;

- Although the Company claims it will not enter such contracts, Piedmont could be improperly rewarded under the Plan if it contracted for gas supplies with first-of-the-month price purchase rights;

- The Plan could provide Piedmont with the incentive not to release unutilized capacity which has a high delivered cost of gas;

- Piedmont's ability to select which gas supplies are sold off-system may adversely impact the Company's sales customers;
- As the length of time increases between the most recent near design peak day and the forecast period, Piedmont should consider more conventional approaches to design peak day forecasting; and
- Piedmont's hedging program is too small to achieve any meaningful price volatility mitigation.

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APPENDIX A

PERFORMANCE INCENTIVE PLAN

SERVICE SCHEDULE NO. 316
Performance Incentive Plan

Applicability

The Performance Incentive Plan (the Plan) replaces the annual reasonableness or prudence review of the Company's gas purchasing activities overseen by the Tennessee Regulatory Authority (Authority or TRA). The Plan does not preclude the Authority from conducting an independent investigation into or examination of any aspect of the Plan or the Company's conduct thereunder. The Plan is designed to provide incentives to the Company in a manner that will produce rewards for its customers and its stockholders and improvements in the Company's gas procurement and capacity management activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period. The Plan will continue until the Plan is either (a) terminated at the end of a plan year by not less than 90 days notice by the Company to the Authority or (b) the Plan is modified, amended or terminated by the Authority on a prospective basis.

Overview of Structure

The Plan establishes a predefined benchmark index to which the Company's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees and the treatment of off-system sales and wholesale interstate sale for resale transactions. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 75%-customers / 25%- stockholders basis for the Plan year commencing on July 1, 2006.

The Plan also is designed to encourage the Company to actively market off-peak unutilized transportation and storage capacity on pipelines in the secondary market. It also addresses the sharing of asset management fees paid by asset managers, and other forms of compensation received by the Company for the release and/or utilization of the Company's transportation and storage assets by third-parties. The Company shall notify the TRA Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan. The net incentive benefits or costs of such activities will be shared between the Company's customers and the Company utilizing a 75%-customers / 25%-stockholders formula commencing on July 1, 2006.

Every three years the Company's activities under the Plan will be reviewed comprehensively by an independent consultant. The first triennial review shall occur in the autumn of 2008. The scope of the review may include all transactions and activities related to the Performance Incentive Plan, including, but not limited to, natural gas procurement, capacity management, storage, hedging, reserve margins, and off-system sales.

The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually. In connection with the Performance Incentive Plan, the Company shall file with the Authority Staff, and supply a copy to the Consumer Advocate and Protection Division of the Tennessee Attorney General (CAD), and update each year, a Three Year Supply Plan. The Company will obtain firm capacity and/or gas supply pursuant to such plan.

Commodity Costs

Each month the Company will compare its *total city gate commodity and cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as:

$$I = F_f(P_0K_0 + P_1K_1 + P_cK_c + \ldots P_\alpha K_\alpha) + F_0O + F_dD; \text{ where}$$
$$F_r + F_0 + F_d = 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under the Company's FT service agreements.

P = the Inside FERC Gas Market Report price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gulf Transmission (CGT) - mainline, and subscript α denotes new incremental firm services to which the Company may subscribe in the future.[2] The indices used for calculating Midwestern capacity shall be those produced by Natural Gas Intelligence for monthly purchases and Gas Daily for daily purchases. The commodity index prices will be adjusted to include the appropriate pipeline

[1] Gas purchases associated with service provided under Texas Eastern Transmission Company Rate Schedule SCT shall be excluded from the incentive mechanism. The Company will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, the Plan will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, the Company will exclude any commodity costs incurred downstream of the city gate to storage so that the Company's actual costs and the benchmark index are calculated on the same basis.

[2] To the extent that the Company renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, the Company shall modify the monthly commodity price index to reflect such discount.

maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under the Company's FT service agreements.[3]

K = the fraction (relative to total maximum daily contract entitlement) of the Company's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[4]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to the Company's system using transportation arrangements other than the Company's FT contracts.

0 = the weighted average of Inside FERC Gas Market Report first-of-the-month price indices, plus applicable IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by the Company and delivered to the Company's system using transportation arrangements other than the Company's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from Gas Daily for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate transportation commodity charges and fuel retention to the city gate.

<u>Gas Supply Reservation Fees</u>
The Company will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, the Company will solicit bids for gas supply contracts containing a reservation fee.

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[3] Capacity released for a month shall be excluded from the benchmark calculation for that month, excluding capacity released under an agreement where the Company maintains city gate delivery rights for the released capacity during such month.

[4] Because the aggregate maximum daily contract quantities in the Company's FT contract portfolio vary by month over the course of the year, the weights will be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, will also vary as the Company renegotiates existing or adds new FT contracts. As new contracts are negotiated, the Company shall modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements. Citygate benchmark calculations shall be computed utilizing the Company's Design Day delivery requirements (deliveries required on a peak day).

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using the Company's firm transportation and capacity entitlements (the costs of which are recovered from the Company's ratepayers) shall be credited to the Plan and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by the Company in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, the Company will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between the Company's actual costs and such index price is taken into account under the Plan. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared with customers on a 75%- customer / 25%-stockholders basis.

Capacity Management

To the extent the Company is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings and/or asset management fees, or other forms of compensation associated with such activities, shall be shared by the Company and customers according to the following sharing formula: 75%-customers / 25%-stockholders. The Company shall notify the TRA Staff and the Consumer Advocate and Protection Division of the Office of the Attorney General (CAD) of all "other forms of compensation" prior to inclusion of such compensation in the Plan.

Hedging Activities

The Company may engage in hedging transactions[5] within the PGA/ACA mechanism. Costs related to hedging transactions may be recovered through the ACA account; provided, however, that such costs recovered through the ACA account shall not exceed one percent (1%) of total annual gas costs. Costs related to hedging transactions recoverable through the ACA account shall be defined as all direct, transaction related costs arising from the Company's prudent efforts to stabilize or hedge its commodity gas costs including, without limitation, brokerage fees, margin requirements, and the costs of financial instruments. All monthly gains and losses shall be (credited)/debited to the ACA account.

Determination of Shared Saving

Each month during the term of the Plan, the Company will compute any gains or losses in accordance with the Plan. If the Company earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If the Company incurs a loss, that same IPA will be credited with such loss. During a Plan year, the Company will be limited to overall gains or losses totaling $1.6 million. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in the Company's Actual Cost Adjustment (ACA) account. The offsetting

[5] Hedging transactions, as used herein, shall include but not be limited to futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs.

entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, the Company may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Gains or losses accruing to the Company under the Plan will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period. The Company is subject to a cap on overall incentive gains or losses of $1.6 million annually.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism. Subject to approval by the TRA, the Company may also propose to refund positive IPA balances on an intra-year basis by making direct bill credits to all customers (except interruptible transportation customers) where such direct bill credit would be beneficial to customers.

<u>Filing with the Authority</u>
The Company will file calculations of shared savings and shared costs quarterly with the Authority not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year. Unless the Authority provides written notification to the Company within 180 days of the annual reports, the Incentive Plan Account shall be deemed in compliance with the provisions of this Service Schedule. The Authority Staff may expand the time for consideration of the annual reports by up to an additional sixty (60) days upon written notification to the Company or longer by mutual agreement or upon a showing of good cause.

Periodic Index Revisions
Because of changes in the natural gas marketplace, the price indices utilized by the Company, and the composition of the Company's purchased gas portfolio may change. The Company shall, within sixty (60) 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 justification to the Company within sixty (60) days of such notice, the price indices shall be deemed approved as proposed by the Company.

Gas Supply Incentive Compensation Program
The Company has in place a Gas Supply Incentive Compensation Program (the Program) designed to provide incentive compensation to selected Gas Supply non-executive employees involved in the implementation of the the Company's Incentive Plan and Secondary Marketing Programs in a manner consistent with the benefits achieved for customers and shareholders through improvements in gas procurement and secondary marketing activities. Participants in the program receive incentive compensation as recognition for their contribution to the customers and shareholders of the Company through lower gas costs and gains related thereto. Performance measures are established for the Program each year.

During the time this tariff is in effect, the Company will continue to have in place the Gas Supply Incentive Compensation Program, as detailed to the Authority, as it relates to the Company's Incentive Plan. The Company will advise the Authority in writing of any changes to the Program, and unless the Company is advised within 60 days, said changes will become effective. The Authority may expand the time for consideration of such changes upon written notification to the Company. No filing for prior approval is required for changes in the performance measures.

Triennial Review
A comprehensive review of the transactions and activities related to the Performance Incentive Plan shall be conducted by an independent consultant once every three years. The initial triennial review shall be conducted in the autumn of 2008 and subsequent triennial reviews shall be conducted every third year thereafter. The TRA Staff, the CAD, and the Company shall make an effort to maintain a list of no less than five (5) mutually agreeable independent consultants or consulting firms qualified to conduct the aforementioned review. Any dispute concerning whether an independent consultant shall be added to the list shall be resolved by the TRA Staff, after consultation with the Company and the CAD. For each review, the TRA Staff shall select three (3) prospective independent consultants from that list. Each such consultant shall possess the expertise necessary to conduct the review. The TRA Staff shall provide the list of

prospective independent consultants to the Company and the CAD via e-mail. The Company and the CAD shall have the right, but not the obligation, to strike one (1) of the prospective independent consultants from the list by identifying the stricken consultant in writing to the TRA Staff within thirty (30) days from the date the list is e-mailed. The TRA Staff shall select the independent consultant from those remaining on the list after the Company's and the CAD's rights to strike have expired. The cost of the review shall be reasonable in relation to its scope. Any and all relationships between the independent consultant and the Company, the TRA Staff, and/or the CAD shall be disclosed, and the independent consultant shall have had no prior relationship with either the Company, the TRA Staff, or the CAD for at least the preceding five (5) years unless the Company, the TRA Staff and the CAD agree in writing to waive this requirement. The TRA Staff, the CAD and the Company may consult amongst themselves during the selection process; provided, however, that all such communications between the parties shall be disclosed to any party not involved in such communication so that each party may participate fully in the selection process.

The scope of the triennial reviews may include all transactions and activities related either directly or indirectly to the Performance Incentive Plan as conducted by the Company or its affiliates, including, but not limited to, the following areas of transactions and activities: (a) natural gas procurement; (b) capacity management; (c) storage; (d) hedging; (e) reserve margins; and (f) off-system sales. The scope of each triennial review shall include a review of each of the foregoing matters as well as such additional matters as may be reasonably identified by the Company, the TRA Staff, or the CAD relative to the operation or results of the Performance Incentive Plan.

The Company, the TRA Staff, or the CAD may present documents and information to the independent consultant for the independent consultant's review and consideration. Copies of all such documents and information shall be presented simultaneously to the independent consultant and all other parties.

The independent consultant shall make findings of fact, as well as identify and describe areas of concern and improvement, if any, that in the consultant's opinion warrant further consideration; however, the independent consultant shall not propose changes to the structure of the Performance Incentive Plan itself. The independent consultant shall complete and issue a written report of its findings and conclusions by July 1 of the year immediately following the triennial review. The report deadline may be waived by the written consent of the TRA Staff, the Company, and the CAD.

The independent consultant shall not propose changes to the structure of the Performance Incentive Plan itself; however, the TRA Staff, the Company, or the CAD may use the report of the independent consultant as grounds for making recommendations or proposed changes to the Authority, and the TRA Staff, the Company, or the CAD may support or oppose such recommendations or proposed changes. Any proposed changes to the structure of the Performance Incentive Plan resulting from the initial triennial review or subsequent triennial reviews, whether adopted by agreement or pursuant to a ruling of the Authority, shall be implemented on a prospective basis only beginning with the incentive plan year immediately following such agreement or ruling.

The cost of the triennial reviews shall be paid initially by the Company and recovered through the ACA account. The TRA Staff may continue its annual audits of the IPA and the ACA account, and the triennial reviews shall not in any way limit the scope of such annual audits. The CAD retains all of its statutory rights, and the triennial reviews shall not in any way affect such rights.