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February 19, 2013

VIA HAND DELIVERY

Executive Director Earl Taylor
c/o Sharla Dillon
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

Re: ***Review of Piedmont Natural Gas Company, Inc.'s Incentive Plan Account Relating to Asset Management Fees*; Docket No. 05-00165**

Dear Mr. Taylor:

Enclosed please find an original and five (5) copies of the public redacted version of the Review of Performance Incentive Plan and Capacity Resources, dated November 2012, which has been prepared in compliance with the TRA *Order Approving Settlement* dated December 14, 2007. Filed along with this is a confidential version, submitted under seal.

Please file the original and four copies of this material and stamp the additional copy as "filed." Then please return the stamped copy to me by way of our courier.

Should you have any questions concerning this matter, please do not hesitate to contact me at the email address or telephone number listed above.

Sincerely,

David Killion

Enclosures

11620580.1

REDACTED

PUBLIC VERSION

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

NOVEMBER 2012

PREPARED BY:

EXETER

ASSOCIATES, INC.
10480 Little Patuxent Parkway
Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

PAGE

LIST OF TABLES

PAGE

FIGURE

PAGE

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 in several proceedings, including 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 ("2006 Settlement") which was approved by the TRA effective July 1, 2006.

The 2006 Settlement, among other things, provides for periodic independent reviews 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. ("Exeter") was selected through an RFP process by the Settling Parties to perform the independent review envisioned under the 2006 Settlement for the period July 1, 2008 through June 30, 2011 ("review period"). Exeter was previously selected to perform the first independent review

provided for under the 2006 Settlement which covered the period July 1, 2006 through June 30, 2008 ("2008 Review").

A Draft Report presenting the findings, results and conclusions of Exeter's current review ("2011 Review") was provided to the Settling Parties on September 5, 2012 . On November 16, 2012, 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 November 19, 2012, 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.

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 criterion 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 six interstate pipelines during the review period: Columbia Gas Transmission ("Columbia Gas"), Columbia Gulf Transmission ("Columbia Gulf"), East Tennessee Natural Gas ("East Tennessee"), Midwestern Gas Transmission ("Midwestern"), Tennessee Gas Pipeline ("Tennessee Gas") and Texas Eastern Transmission ("Texas Eastern"). Of these six interstate pipelines, Piedmont is interconnected to four: Columbia Gulf, East Tennessee, Tennessee Gas and Texas Eastern. These interconnects are summarized in Table 1. Figure 1 presents a map of the Company's service territory and the interstate pipelines serving Piedmont. The interstate pipeline services purchased by Piedmont during the review period are described in the following section. Table 2 summarizes the primary services purchased by Piedmont to meet customer demands for the winter of 2010–2011.[1] 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, East Tennessee, Tennessee Gas and Texas Eastern provide for the delivery of gas supplies directly to

[1] Piedmont's arrangements with East Tennessee are excluded from Table 2 because the East Tennessee services do not provide incremental delivered supplies.

Table 1

PIEDMONT NATURAL GAS COMPANY
Summary of Interstate Pipeline Interconnects

	Pipeline	Percent of Peak Day	Meter Number	Meter Type	Area Served	County	City
1.	Columbia Gulf	[redacted]	4016	Turbine (8")	Southeastern portion of Nashville distribution system	Davidson	Nashville
2.	Columbia Gulf		4088	Turbine (4")	Eastern portion of Nashville distribution system	Wilson	Nashville
3.	Columbia Gulf		4183	Turbine (4")	Southern portion of Nashville distribution system	Williamson	Nashville
4.	Texas Eastern		70316	Turbine	City of Hartsville distribution system	Trousdale	Hartsville
5.	Texas Eastern		73423	Ultrasonic (6")	Southeastern portion of Nashville distribution system	Rutherford	Nashville
6.	Tennessee Gas		020280-01	Rotary	City of Greenbrier distribution system	Robertson	City of Greenbrier
7,	Tennessee Gas		020309-01	4" Sr Orifice Tube	Ashland City distribution system	Cheatham	Ashland City
8.	Tennessee Gas		020312-0, 020312-A	Ultrasonic (12")	Main portions of Nashville distribution system	Davidson	Nashville
9.	Tennessee Gas		020600-01	Turbine	City of White House distribution system	Robertson	White House
10.	Tennessee Gas		020610-0	Rotary (2")	City of Fairview distribution system	Dickson	Fairview
11.	Tennessee Gas		020846-0	Rotary (3M)	Cheatham County Industrial Park	Cheatham	Cheatham Co. Industrial Park
12.	Tennessee Gas		20753-0	Rotary (1M)	Robertson County outside city limits of Greenbrier and White House	Robertson	Outside Greenbrier City Limits
13.	East Tennessee		59218	Ultrasonic (4")	Northern portions of Nashville distribution system	Summer	Summer

Figure 1

Piedmont Service Territory and Pipeline Interconnects

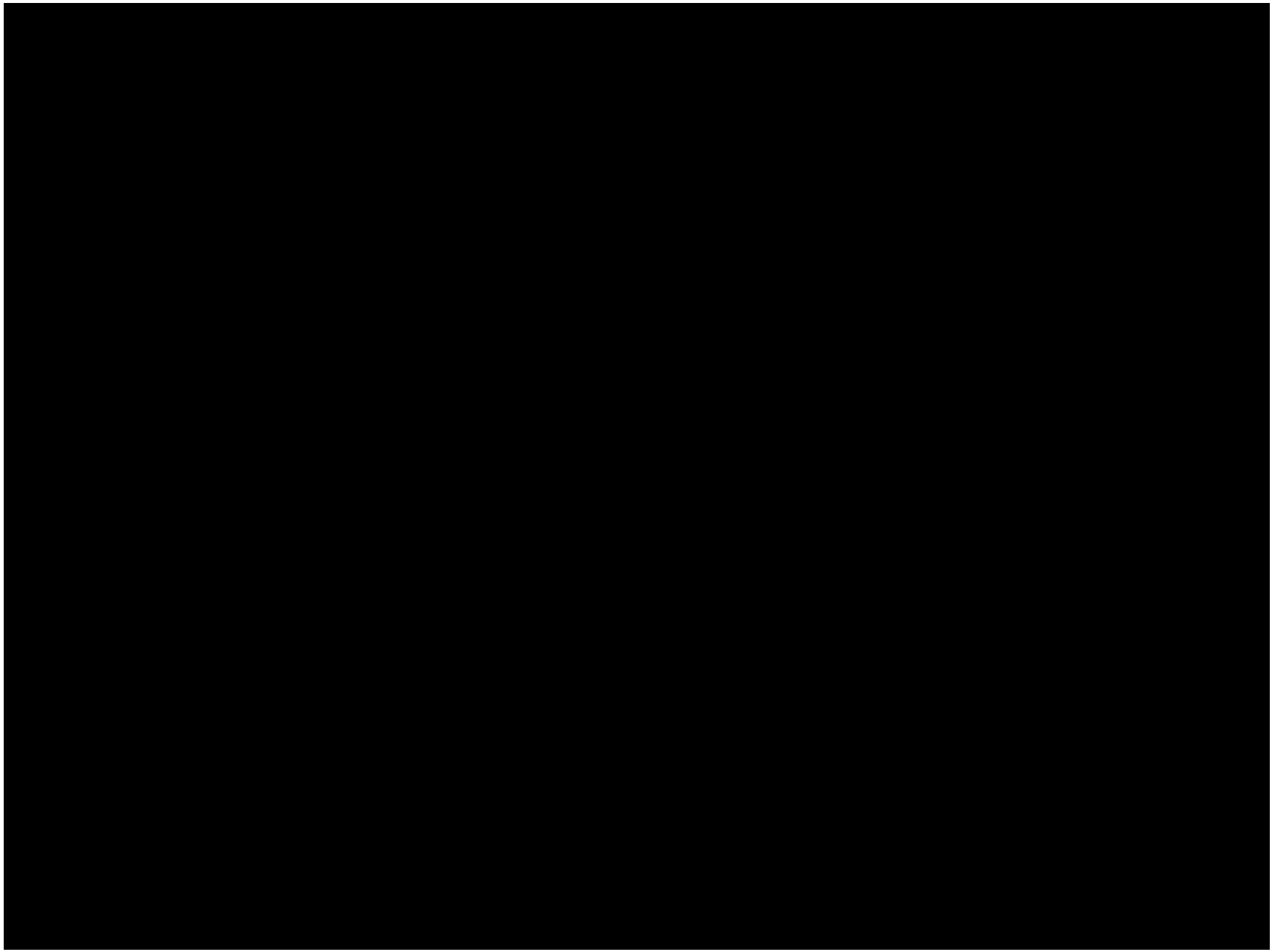

Table 2

PIEDMONT NATURAL GAS COMPANY
Summary of Primary Design Day Capacity Resources
2010 - 2011 Winter Season
(Dth)

Pipeline - Service	Contract No.	MDQ		Available Quantity		Contract Expiration
		Winter	Summer	Winter Season	Annual	
Columbia Gas						
Storage Service (FSS/SST)	38017 38052	10,000	5,000	611,870	0	3/31/2013
Columbia Gulf						
Firm Transportation (FTS-1)	76812	5,000	5,000	755,000	1,825,000	10/31/2013
Firm Transportation (FTS-1)	43462	5,000	4,601	755,000	1,739,614	10/31/2012
Midwestern Gas						
Firm Transportation (FT-A) (FT-B)	FA0342 FB0006	100,000	100,000	15,100,000	36,500,000	01/06/2023
Tennessee Gas						
Firm Transportation (FT-A)	237	74,100	74,100	11,189,100	27,046,500	10/31/2014
Storage Service (FT-BH/FS-MA)	6815 2A	49,828	0	2,901,943	0	10/31/2014
Storage Service (FT-BH/FS-PA)	2400 2A	6,072	0	672,091	0	10/31/2014
Texas Eastern						
Firm Transportation (FT-1)	910473	10,000	0	1,510,000	1,510,000	03/31/2019
Firm Transportation (SCT)	800059	1,677	1,677	84,409	204,035	10/31/2012
Piedmont LNG	None	92,000	0	920,000	0	None
Total Capacity Resources		353,677	190,378	34,499,413	68,825,149	

Piedmont's system. As subsequently explained, although Piedmont is not directly interconnected with Columbia Gas, Piedmont's transportation arrangement with Columbia Gas is operated as though it 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, East Tennessee and Columbia Gulf, but not directly to Piedmont's system. Midwestern-sourced gas supplies can be delivered to the west side of Piedmont's system by

Tennessee Gas, to the northern portion of Piedmont's system by East Tennessee, and to the east side of Piedmont's system by Columbia Gulf. Piedmont's Midwestern-sourced delivery arrangements are discussed in greater detail later in this section of the Final Report.

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. Gas deliveries to and from Columbia Gas are handled through a combination of facilities jointly owned and operated by Columbia Gas and Columbia Gulf and an operational balancing agreement ("OBA"). 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 a discounted rate interruptible backhaul transportation arrangement with Columbia Gulf during the review period. This arrangement was utilized to deliver gas from Columbia Gulf's interconnect with Midwestern at Walnut Grove, Tennessee to Piedmont's system.

2.1.3 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 7 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 (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:

Tennessee Gas Pipeline Capacity	
Zone Leg	**MDQ**
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

Piedmont is able to segment its capacity under Contract No. 237 to deliver 21,000 Dth per day of Gulf Coast sourced supplies and at the same time 21,000 Dth per day of Midwestern-sourced supplies.

Piedmont also purchased a discounted rate transportation service from Tennessee Gas under Contract No. 46715 (Rate Schedule FT-B). Tennessee Gas Contract No. 46715 is a back-haul transportation arrangement that provides for the delivery of gas from the Market and Production area storage accounts up to 55,900 Dth per day as well as Tennessee Gas' interconnect with Midwestern at Portland, Tennessee to Piedmont's system. The effective contract quantity under Contract No. 46715 that can move Midwestern sourced gas is 26,000 Dth per day.

2.1.4 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 can be delivered to the west side of Piedmont's distribution system by Tennessee Gas, to the northern portion of Piedmont's distribution system by East Tennessee 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 No. FB0006 provides for firm transportation from Portland, Tennessee to an interconnect with Columbia Gulf at Walnut Grove, Tennessee, and to an interconnect with East Tennessee at Boat Dock in Summer, Tennessee.

Since Piedmont is not directly interconnected with Midwestern, Midwestern-sourced gas supplies are delivered to Piedmont by other pipelines. Multiple options exist for the delivery of Midwestern-sourced gas supplies to Piedmont. For purpose of evaluating Piedmont's performance under the Plan during the review period, Piedmont selected Midwestern delivery paths based on the anticipated winter design peak day requirements of its system. These paths varied from time to time and are identified in Table 3. The particular path selected each for each period did not have a material impact on Piedmont's performance under the Plan.

Table 3

PIEDMONT NATURAL GAS COMPANY
Summary of Midwestern Delivery Paths
(Dth)

2.1.5 East Tennessee Natural Gas

To meet growing demand on the northern portion of its system, Piedmont established an interconnect with East Tennessee in November 2009. Piedmont's arrangement with East Tennessee (Contract No. 410158) provides for the delivery of

25,000 Dth per day from an interconnect with Midwestern at Boat Dock to a delivery point on Piedmont's system in Hendersonville, Tennessee. This arrangement is used to deliver Midwestern-sourced gas supplies to Piedmont's system via the Hendersonville interconnect. The expiration date of the East Tennessee contract is October 31, 2021.

2.1.6 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 as it is used to serve the City of Hartsville, Tennessee.

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 Gas.

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

Piedmont operates an on-system LNG facility capable of producing up to [redacted] Dth per day. The LNG facility can produce at maximum levels for approximately ten days.

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 4 summarizes the number of customers served and annual throughput by service class for 2008, 2009 and 2010.

Table 4

PIEDMONT NATURAL GAS COMPANY
Annual Customers and Volumes by Class

3.0 PERFORMANCE INCENTIVE PLAN

This section of our Final 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 Final Report. Table 5 summarizes Piedmont's performance under Plan for the review period. Table 5 reflects a correction to the information initially filed by the Company with the Commission related to Plan results for October 2008. The need for this correction was discovered by the Company as a result of Exeter's review, and the correction is also reflected in Tables 8 and 9. More detailed information regarding Piedmont's performance under the Plan is presented later in this section of the Final Report.

Table 5

PIEDMONT NATURAL GAS COMPANY
Summary of Performance Incentive Plan
Review Period Results

Plan Year	Gain/(Loss)		
	Total	**Ratepayers**	**Company**
July 2008 – June 2009	$6,308,392	$4,731,294	$1,577,098
July 2009 – June 2010	5,253,206	3,939,904	1,313,301
July 2010 – June 2011	2,924,191	2,193,143	731,048
Total – Review Period	**$14,485,789**	**$10,864,341**	**$3,621,447**

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 FOM and daily gas purchases at major natural gas trading locations. These average, or market, 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 charged to Piedmont, and sales customers' gas costs are reduced by the amount charged 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 interstate pipeline 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 arrangements 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 firm 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 purchase 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 firm transportation charges. Shown in Table 6 for illustrative purposes are the calculations of the MBIP for February 2009 and February 2010. These two months were selected because they are representative of Piedmont's pre- and post-East Tennessee interconnect arrangements.

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. [redacted] Also shown in Table 7 is the range in delivered prices (i.e., the difference between the highest and lowest price). An active daily participant in the natural gas market such as Piedmont would be well aware of these price relationships. Shown on Table 8 is a summary of Piedmont's gas commodity procurement incentive mechanism gains and loss by month and purchases by type (i.e., FOM, spot market, other citygate). Table 8 reveals that [redacted] of Piedmont's commodity gas purchases were [redacted]. Gains and losses by type of purchase under the gas commodity procurement incentive mechanism are summarized in Table 9. [redacted]

Table 6

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

[redacted]

Table 7

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

[redacted]

Table 8

PIEDMONT NATURAL GAS COMPANY
Summary of Commodity Procurement Purchases and Plan Rewards
(Dth)

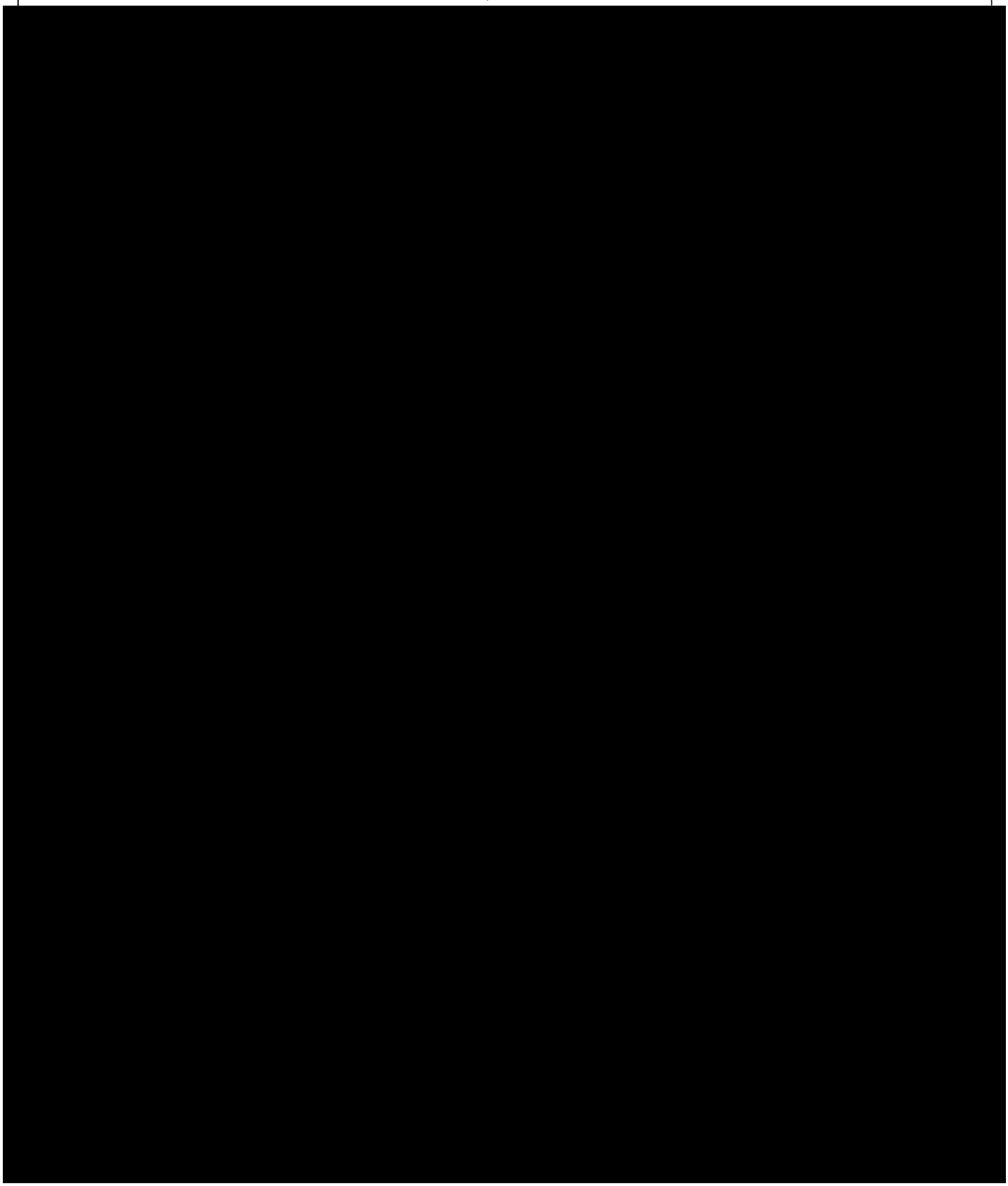

Table 9

PIEDMONT NATURAL GAS COMPANY
Gas Commodity Procurement Mechanism
Gains/(Losses) by Type of Purchase

Purchase Type	Gain/(Loss)
First-of-the-Month Spot Market Other Citygate	[redacted]
Total	

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, it is our 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 commodity procurement component of 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. As observed in Table 8, [redacted]

[redacted] During October 2008, [redacted] was experienced under the commodity procurement component of the Plan.

Table 10 illustrates, as an example, the relative ease at which Piedmont was able to realize a reward in February 2009. [redacted]

[redacted] Piedmont would have been well aware of this price differential at the time it was making its February 2009 purchasing decisions. Piedmont realized its most significant rewards under the commodity procurement component of the Plan when the range in delivered prices were the most significant.

Table 10

PIEDMONT NATURAL GAS COMPANY
Illustration of February 2009 Commodity Cost Reward
(Dth)

[redacted]

In its comments on our 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 claimed 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 agrees that the interests of Piedmont and its customers are aligned under this aspect of the Plan. Nevertheless, it is Exeter's 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 gas cost "savings" that would have been realized without the existence of the Plan.

However, we do note that in the earlier February 2009 example MBIP calculation presented in Table 6, Piedmont had released 30,000 Dth of its 100,000 Dth of Midwestern capacity. This had the effect of reducing the reward realized under the Plan. In addition, by design, the rewards realized by Piedmont under the commodity procurement component of the Plan are a function of the range in delivered gas prices. That is, the more significant the range the more significant the reward. As observed in Table 7, the range in delivered gas prices has declined. This decline is due to factors such as the development of Marcellus Shale gas supplies in the Appalachian Basin. This reduced range in delivered gas prices is expected to continue, and Piedmont's ability to generate rewards under the commodity procurement component of the Plan will be diminished.

3.2 Supplier Reservation Fees

3.2.1 Background and Description

Piedmont considers demand charges paid to suppliers and any commodity adder to the applicable index price under its firm gas supply arrangements to be supplier reservation charges. The Plan allows Piedmont to recover 100 percent of its gas supply reservation fees with no profit or loss potential. [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. Therefore, we have no concerns with the supplier reservation charges incurred by Piedmont during the review period.

3.3 Capacity Management

Piedmont's capacity management activities during the review period included asset management arrangements, capacity release and off-system sales. Table 11 summarizes the revenues from these activities for the review period. Piedmont is entitled to retain 25 percent of the revenues, up to $1.6 million including gains under the commodity procurement mechanism, derived from these activities. The sharing procedures for these activities are consistent with those adopted in other jurisdictions.

3.3.1 Asset Management Arrangements

a) Background and Description

Historically, Piedmont has relied on asset management arrangements to generate revenues under the Plan. However, in late 2007, the FERC issued a Notice of Proposed Rulemaking ("NOPR") which, among other things, sought to define the scope of permissible AMA arrangements. Due to the uncertainty over the FERC's final determinations with respect to AMAs, Piedmont believed it prudent to delay entering into new AMAs until the uncertainty was resolved. That uncertainty was resolved in June 2008 with the FERC's issuance of Order No. 712, and Piedmont resumed its practice of entering into asset management arrangements.

Table 11

PIEDMONT NATURAL GAS COMPANY
Summary of Capacity Management and Off-System Sales Revenues
(Dth)

[redacted]

Piedmont entered into three AMAs during the review period. Each AMA was awarded through an RFP process. Under the AMAs, Piedmont released certain transportation and storage capacity and gas supply contracts to the AMA manager, which utilized the capacity and supply contracts to meet Piedmont's gas supply requirements. Piedmont remained responsible for all pipeline demand charges associated with the released capacity. The AMA manager was entitled to utilize any capacity or supply contract it was assigned that was not required to serve Piedmont to pursue its own business interests. Generally, each day, Piedmont would determine the quantity of gas it would require from the AMA manager by delivering pipeline and its storage injection and withdrawal activity ("virtual dispatch"), and convey this information to the AMA manager. Piedmont paid pipeline variable charges based on virtual dispatch.

Piedmont entered into an AMA with [redacted] for the period November 2008 through October 2009. [redacted] paid Piedmont a fee of [redacted] for the assigned assets. The fee was paid to Piedmont in November 2008.

Piedmont entered into an AMA with [redacted] for the period November 2009 through October 2010. [redacted] paid Piedmont a fee of [redacted] for the assigned assets. The fee was paid to Piedmont in November 2009.

Piedmont entered into an AMA with [redacted] for the period November 2010 through October 2011. [redacted] paid Piedmont a fee of [redacted] for the assigned assets. The fee was paid in 12 equal monthly installments.

b) Conclusions and Results

Our investigation revealed a potential concern with Piedmont's AMA activities. Under the Plan, Piedmont is subject to a cap on overall incentive gains or losses of $1.6 million annually. As a practical matter, Piedmont has the ability to determine the payment schedule for the AMA fees it receives (e.g., monthly installments, one annual fee). Therefore, the potential exists for Piedmont to circumvent to $1.6 million Plan cap by adjusting the AMA payment schedule. However, our review found that Piedmont did not adjust the AMA payment schedule to circumvent the annual cap during the review period.

3.3.2 Capacity Release

a) Background and Description

Under its asset management arrangements, Piedmont assigned most of its capacity assets to the AMA Manager and, therefore, capacity release opportunities were limited. As shown in Table 11, Piedmont generated $3,995,524 in capacity release revenues during the review period. A significant percentage of these revenues were realized during the period July 2008 through October 2008 when no AMA was in place.

Piedmont's review period capacity release activity initially included the full release of all Midwestern capacity to supplier Eagle Energy Partners ("Eagle") through October 31, 2008. That is, Piedmont released 100,000 Dth of capacity to Eagle for the period February 1, 2008 through October 31, 2008. [redacted]

[redacted]

[redacted]

b) Results and Conclusions

[redacted]

[redacted] However, our review found that inclusion of the Midwestern capacity in the MBIP was in technical compliance with the terms and conditions of the Plan.

Our current and prior review of the Plan 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 Monthly Benchmark Index Price. This gives Piedmont

the incentive not to release unutilized capacity which would have a high delivered cost of gas because it could increase the reward realized under the commodity procurement component of the Plan. As indicated previously, Midwestern-sourced gas was generally Piedmont's highest cost delivered supply during the review period, and maintaining rather than releasing this capacity would have increased the reward realized under the commodity procurement component of the Plan. A determination as to whether Piedmont maximized the release of Midwestern capacity would need to be made on a real-time basis rather than through an after-the-fact review. This is because the variables affecting Piedmont's capacity release decision are constantly changing. These variables include capacity release values, commodity prices at pipeline receipt point locations and customer load requirements. Our review did not find evidence that Piedmont conducted its capacity release activity to improperly realize rewards under the commodity procurement component of the Plan.

3.3.3 Off-System Sales

a) Background and Description

As with capacity release activity, because Piedmont assigned most of its capacity assets to Asset Managers under the AMAs, Piedmont's ability to engage in off-system sales while the AMAs were in place was limited. AMAs were in place beginning in November 2008. Once the AMAs were in place, Piedmont's off-system sales activity declined significantly. Off-system sales opportunities after the AMAs were in place were generally limited to those transactions which did not require the use of interstate pipeline capacity (e.g., production area sales). [redacted]

[redacted]

[redacted]

A general concern with Piedmont's off-system sales activity, particularly from May 2009 forward, is that it has the potential to adversely impact the gas costs of sales customers if the supplies sold off-system are later replaced with higher cost supplies. It appears beyond coincidence that Piedmont would experience operational constraints,

being in an excess supply situation, requiring it to sell gas off-system only during months or periods when FOM prices were below current market prices. The extent to which sales customers may has been adversely impacted by Piedmont's off-system sales activities is unknown because it cannot readily be determined, except on a real-time basis, when purchases were made to replace the supplies sold off-system. However, one approach to evaluating the impact would be to assume supplies sold off-system were replaced through FOM baseload purchases the following month. [redacted]

[redacted]

A final concern with the administration of Piedmont's off-system sales activities which is highlighted by the Company's activities during [redacted]

[redacted]

[redacted] It is our experience that excess supply situations are rare. 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. The date currently used by Piedmont is January 23, 2003, when 57.9 heating degree days were recorded. Piedmont's design peak day temperature criterion was 60.7 heating degree days during the review period.[2] 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 (i.e., January 23, 2003) and the year for which a forecast is being prepared. Finally, a 5 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

[2] For the winter of 2011-2012, Piedmont revised the design peak day used for capacity planning purposes to 67 heating degree days.

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 5 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 design peak day forecast and Exeter's independent forecast compare as follows for the 2010 – 2011 winter season:

Piedmont: [redacted]

Exeter: [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. It should be noted that while conservation efforts decrease gas usage, gas prices declined significantly during the review period, which may result in increases in gas usage. Table 12 identifies the average monthly closing New York Mercantile Exchange ("MYMEX") price since 2008.

Table 12 PIEDMONT NATURAL GAS COMPANY Average Monthly Closing NYMEX Price (Dth)	
Year	**Price**
2008	$9.035
2009	$3.986
2010	$4.393
2011	$4.042
2012 (est.)	$2.800

4.2 Design Peak Day Criteria and Reserve Margin

As previously indicated, Piedmont utilized a day with 60.7 heating degree days for its design peak day criterion during the review period. Piedmont personnel are unaware as to how this criteria was originally selected. Since 1975, temperatures as cold or colder than Piedmont's selected review period 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.

Since the conclusion of the review period, the Company reviewed and revised its design day weather criterion to represent the colder of: (1) the coldest average daily temperature in the last 20 years; or (2) 5 percent warmer than the coldest average daily temperature in the last 30 years. The new design day weather criteria was first used for the winter of 2011-12. The coldest average daily temperature in the last 20 years was 4

degrees Fahrenheit, whereas 5 percent warmer than the coldest average daily temperature in the last 30 years is -2 degrees Fahrenheit. Therefore, the Company is now utilizing -2°F for the design day weather criteria. In the last 30 years, temperatures as cold or colder than -2°F have occurred twice, on January 20, 1985, when an average temperature of -5°F was recorded, and on December 22, 1989, when an average temperature of -4°F was recorded. Piedmont's new design day criteria increases projected design peak day capacity requirements by approximately 30,000 Dth.

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, during the review period, Piedmont's design peak day capacity requirements based on a design peak day of 60.7 heating degree days and maintaining a 5 percent reserve margin, were approximately equal with selecting a design peak day of 63.5 heating degree days and maintaining no reserve margin. Given the heating degree days observed in its service territory since 1975, the use of 63.5 heating degree days as Piedmont's design peak day criterion would be considered reasonable. Therefore, Piedmont's selection of a 60.7 heating degree days as its design peak day and maintaining a 5 percent reserve margin during the review can be considered reasonable. Piedmont's new -2°F design peak day criterion coupled with maintaining a 5 percent reserve margin is a much more conservative approach to design peak day capacity planning, but cannot be considered unreasonable.

4.3 Actual Peak Day

Table 13 summarizes the sendout of firm 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 60.7 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 13

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

Date	HDD	Sendout	
		Actual	Design
January 15, 2009	51	267,408	[redacted]
January 8, 2010	48	265,385	
December 13, 2010	51	260,651	

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 2010 – 2011 winter season totaled [redacted]. Estimated design peak day firm sales requirements, including the 5 percent reserve margin, totaled [redacted]. This capacity surplus was expected to increase by approximately [redacted]. As explained in Section 4.2 of this Report, since the conclusion of the review period, Piedmont has increased its design peak day criteria from 60.7 to 67

heating degree days, which had the effect of increasing design peak day requirements by approximately 30,000 Dth. With this change in design peak day criteria, the capacity surplus no longer exists.

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 2010 – 2011 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 [redacted]. Thus, from a planning perspective, [redacted]. Piedmont attempts to release capacity which is not currently required to meet customer requirements. The excess in winter season capacity resources indicates that, if available and opportunities exist, Piedmont should decrease its dependency on year-round firm transportation capacity and increase its dependency on winter seasonal capacity and winter-only delivered supply services. The availability of winter seasonal services and Piedmont's opportunities to increase its reliance on winter seasonal services is discussed in greater detail in Section 4.7 of this Final Report.

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 design winter season is experienced are [redacted]. As shown on Table 2, the capacity resources available to meet Piedmont's annual requirements total 68.8 Bcf. Based on annual requirements of [redacted]

Piedmont's excess annual capacity balance is discussed further in Section 4.7 of our Final Report.

4.7 Capacity Portfolio Modifications

The RFP scope of work for our review included examination and identification of: (a) the cost of year-round firm transportation and seasonal firm transportation utilized by Piedmont during the review period to meet peak demand; (b) the potential cost of meeting peak demand with more seasonal firm transportation and less year-round firm transportation; and (c) the potential cost of meeting peak demand with more year-round firm transportation and less seasonal firm transportation. Exeter interprets this aspect of the scope of work as requiring Exeter to evaluate whether Piedmont's annual interstate pipeline demand charges can be reduced by modifying the Company's current capacity portfolio.

The charges associated with each non-storage related interstate pipeline firm transportation service purchased by Piedmont at the conclusion of the review period are summarized on Table 14. Actual review period usage is presented on Table 15. [redacted]

[redacted]

Table 14

PIEDMONT NATURAL GAS COMPANY
Summary of Interstate Pipeline Firm Transportation Charges
(Dth)

Pipeline Service	Demand Quantity		Monthly Demand Charge	Annual Demand Cost	Variable Charges
	Daily	Annual			
Columbia Gulf (FTS-1)	9,766	3,564,614	[redacted]	[redacted]	[redacted]
Tennessee Gas					
FT-A	74,100	27,046,500			
FT-B	81,900	29,893,500			
Texas Eastern					
FT-1	10,000	1,510,000			
SCT	1,677	204,035			
Midwestern Gas (FT-A/B)					
FT-A	100,000	36,500,000			
FT-B	100,000	36,500,000			
East Tennessee (FT-APT)	45,000	16,425,000			

Table 15

PIEDMONT NATURAL GAS COMPANY
Summary of Delivered Quantities by Pipeline Location
Exclusive of Off-System Sales Deliveries
(Dth)

[redacted]

For the Tennessee Gas FT-A contract which expires in 2014, if available, replacing this year-round arrangement with a winter season arrangement could reduce Piedmont's annual demand charges. Until recently, the interstate pipelines which serve Piedmont did not offer seasonally sculpted or winter-only firm transportation services. As a result Piedmont was generally forced to purchase year-round service and then either release any unutilized capacity or utilize that capacity to make off-system sales. However, due to the increase in design peak day demands attributable to the Company's change to its design peak day criterion, Piedmont issued an RFP during the summer of 2011 for winter only firm transportation capacity. Bids were received at discounted rates from Columbia Gulf, Tennessee Gas and Texas Eastern. However, no pipeline was willing to offer service for a period greater than one winter. Rather than accepting one of the pipeline bids, Piedmont elected to purchase a winter-only delivered supply service. It is uncertain whether Piedmont will be able to reduce its reliance on year-round transportation service and increase its reliance on winter season upon expiration of its current Tennessee Gas contract. Piedmont is fully aware of the need to reduce its reliance on year-round transportation service and increase its reliance on winter season service. The potential savings associated with a greater reliance on

winter season transportation service is unknown. However, any decrease in the reliance on annual firm transportation capacity and increase in the reliance on winter season arrangements is likely to reduce the revenues received under Piedmont's asset management arrangements. Revenues under Piedmont's AMA would decline because less excess capacity would be available for use by the Asset Manager.

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 2006 Settlement provided for the recovery of hedging 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 costs included amounts paid for financial instruments such as call and put options. Piedmont's allowable hedging costs are limited to 1 percent of actual gas costs. All hedging gains and losses are reflected in the rates of sales customers, and the gains and losses are excluded from the 1 percent cost limit.

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. Initially, 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.

Piedmont utilizes a decile matrix approach to hedge for price. The matrix is developed by utilizing four years of historical NYMEX closing prices for both the winter and summer months, adjusting the prices for inflation and weighting the prices slightly more heavily for the last year of historical prices, and breaking the adjusted NYMEX prices into 10 percent deciles. A sample matrix for June 2011 is presented below:

June 2011 Expiration			
DECILE	**ANNUAL**	**SUMMER**	**WINTER**
90% - MAX	$8.98 - 11.952	$9.998 - 11.952	$8.005 - 9.174
80% - 90%	7.781 - 8.98	8.187 - 9.998	7.472 - 8.005
70% - 80%	7.012 - 7.721	7.085 - 8.187	6.898 - 7.472
60% - 70%	6.174 - 7.012	5.275 - 7.085	6.268 - 6.898
50% - 60%	5.226 - 6.174	4.843 - 5275	5.779 - 6.268
40% - 50%	4.824 - 5.826	4.573 - 4.843	5.368 - 5.779
30% - 40%	4.521 - 4.824	4.386 - 4.573	4.970 - 5.368
20% - 30%	4.325 - 4.521	4.276 - 4.386	4.559 - 4.970
10% - 20%	4.132 - 4.325	4.114 - 4.276	4.190 - 4.559
MIN - 10%	3.053 - 4.132	3.107 - 4.114	3.578 - 4.190
Mean	$6.036	$6.061	$6.000
Median	$5.226	$4.843	$5.779

The Company hedges for price if forward NYMEX prices close at or below the 50th decile level of the matrix. At the 50th decile level of the matrix, the Company hedges 20 percent of the maximum allowed hedging amount for that winter month. If NYMEX prices close at the 40th decile level for a particular winter month within the hedging horizon, an additional 20 percent of the allowed amount for hedging for that month will be used. This continues until the last 20 percent of the allowed amount for hedging is spent when NYMEX prices reach the 10th decile level.

If NYMEX prices within the hedging horizon do not reach or fall below the 50th decile level of the matrix, 10 percent of the amount allowed for hedging will be hedged for each month of the winter season when the date reaches five months before the start

of the winter season. An additional 10 percent of the total allowed amount will be hedged four months before the winter season begins. This continues until 50 percent of the amount allowed for hedging is utilized.

The Company used three primary types of financial instruments for hedging during the review period. These instruments were caps, collars and three-ways. Piedmont's actual hedging activity during the review period is detailed on Tables 16-1, 16-2, and 16-3.

A cap involves buying and selling a call option 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 collar entails purchasing a call option which establishes a ceiling or maximum price the Company would pay for its supply and selling a put option which guarantees a floor price the Company would pay for gas. The revenues received from selling the put option offset a portion of the costs of purchasing the call option. If gas prices fall below the put option strike price, a loss will be experienced by the Company.

Table 16-1

Piedmont Natural Gas Company
Summary of Review Period Hedging Activity
(Dth)

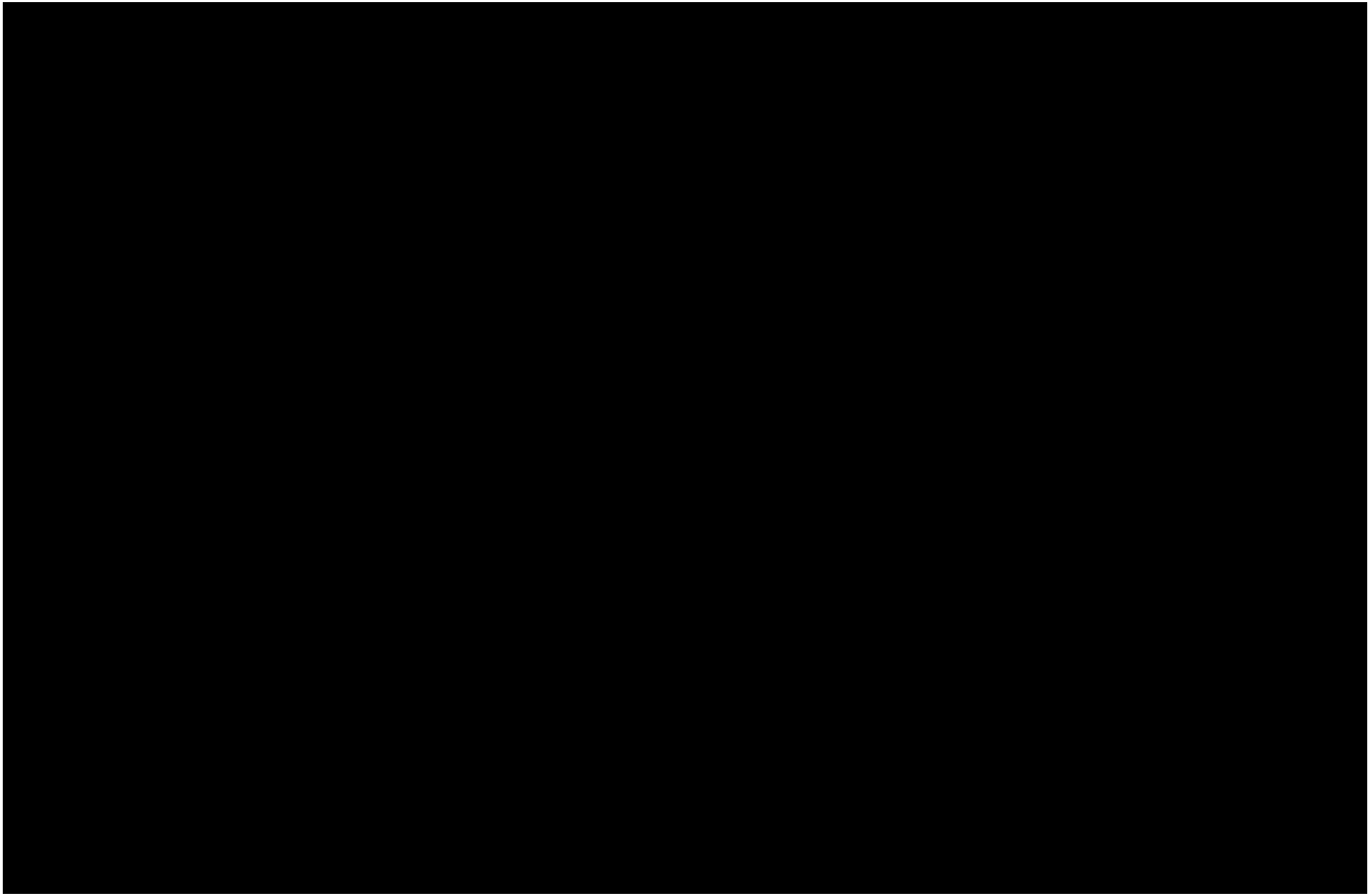

Table 16-2

Piedmont Natural Gas Company
Summary of Review Period Hedging Activity
(Dth)

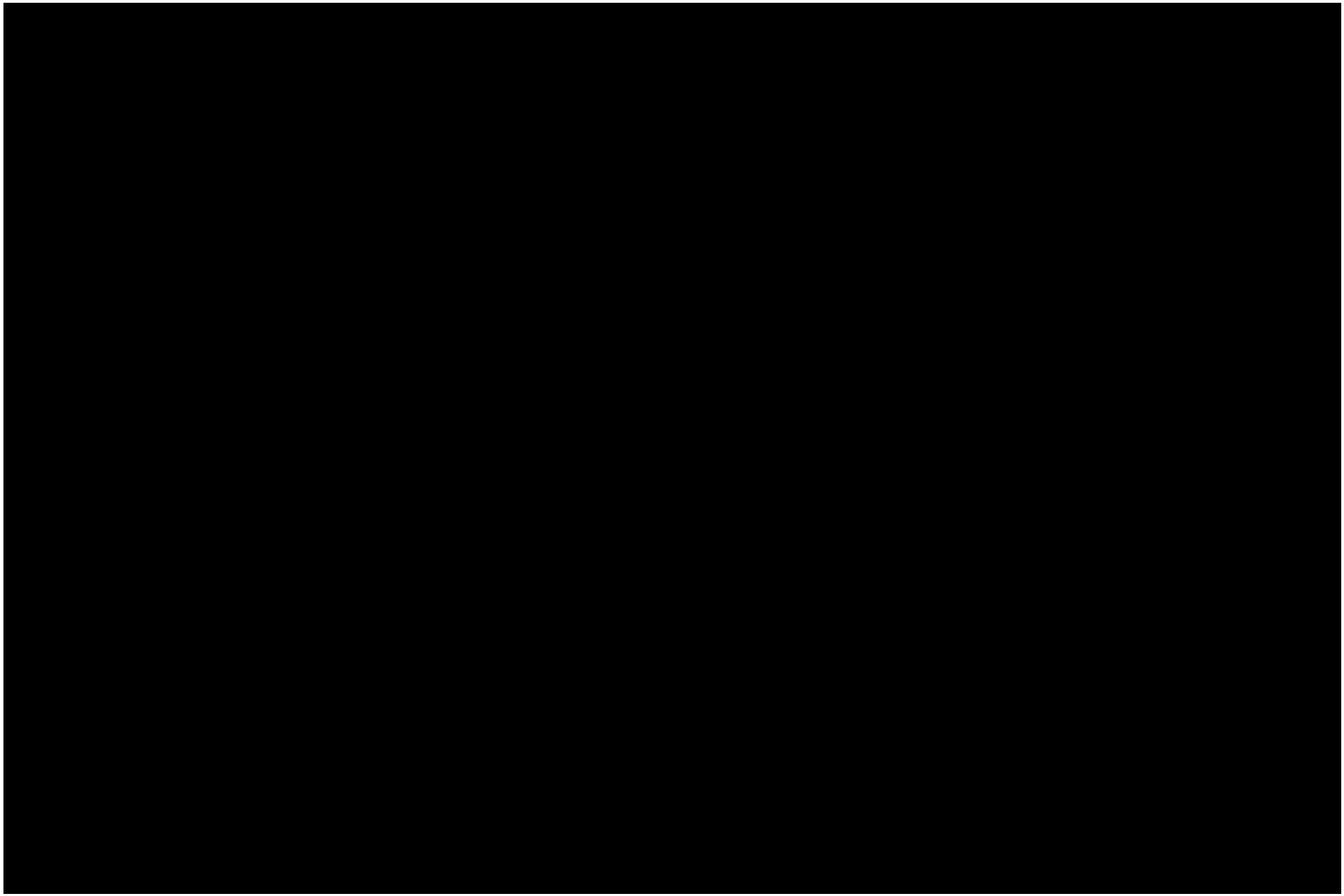

Table 16-3

Piedmont Natural Gas Company
Summary of Review Period Hedging Activity
(Dth)

Under a three-way, 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 gas. 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.

Market prices declined significantly during the review period. As a result, Piedmont sustained substantial losses in conjunction with the sale of put options. As a result, effective November 11, 2009, the Company elected to eliminate both the sale of put and call options from its hedging program and rely exclusively on call options.

As indicated previously, hedging cost recovery is limited to 1 percent of the Company's total annual gas cost. Our review found that Piedmont's hedging costs were less than 1 percent for each year of the review period.

5.2 RFP Requirements

The RFP for the review of Piedmont's performance under the Plan identified for review and assessment specific aspects of Piedmont's hedging program. Those items are addressed in this section of the Final Report.

5.2.1 What were the market conditions during the review period and did Piedmont perform a cost-benefit analysis to support the hedging program?

Natural gas prices declined significantly during the review period. The NYMEX closing price for July 2008, the first month of the review period, was $13.105 per Dth, and declined to $6.888 per Dth by December 2008. During 2009, prices declined further, with an average NYMEX closing price of $3.986 per Dth. Natural gas prices increased slightly during 2010 with an average NYMEX closing price of $4.393 per Dth. For the first half of 2011, the average NYMEX closing price was $4.211 per Dth. Piedmont did not perform a cost-benefit analysis to support its hedging program.

5.2.2 What hedging tools did Piedmont consider and what criteria were used to select hedging tools?

[redacted]

5.2.3 What costs were associated with the different hedging tools used and the potential of losses for Piedmont?

The costs associated with the various hedging tools used by Piedmont are detailed on Tables 16-1, 16.2 and 16-3. As shown on Table 16-3, Piedmont spent $7.15 million to purchase call options. These costs were partially offset from revenue received from the sale of call options ($1.56 million) and put options ($1.75 million). Net

expenditures for call and put options were $3.84 million. In addition, losses of $9.35 million were experienced when the put options sold by Piedmont were exercised. Finally, $32,273 in broker fees were incurred by Piedmont in conjunction with its hedging program. Piedmont has indicated that the potential for losses by selling puts was finite as gas prices could only go to zero.

5.2.4 What was Piedmont's budget for hedging during the review period and were hedges staggered over a predefined period?

Piedmont's allowable hedging costs are limited to 1 percent of actual gas costs. During the review period Piedmont's actual gas cost were $515.22 million, suggesting a maximum allowable spending limit of $5.15 million. Piedmont's actual review period hedging expenditures were $3.84 million plus $32,273 in fees. As shown on Tables 16-1, 16-2 and 16-3. Piedmont's hedges were staggered over time pursuant to the procedures discussed in Section 5.1 of this Final Report.

5.2.5 Were there price triggers for determining hedging volumes and timing?

The price triggers for hedging volumes and timing were described in Section 5.1 of this Final Report.

5.2.6 Identify benefits and costs of the hedging program during the review period, including costs and benefits to customers (both tangible and intangible). Compare costs to customers to estimated costs in the absence of a hedging program.

The costs and benefits of Piedmont's hedging program are identified in Section 5.2.3 of this Final Report.

5.2.7 Review and assessment of Piedmont's (hedging) documentation process.

Piedmont maintains a copy of all monthly RMI price matrices, time stamped deal tickets, price matrices used in evaluation of call purchases, minutes of the Energy Price Risk Management Committee which oversees the Company's hedging program and daily positions and mark-to-market reports. Our review found Piedmont's documentation process satisfactory.

5.2.8 Review of hedging losses during the period and assessment of the cause(s).

The losses experienced under Piedmont's hedging program are detailed in Section 5.2.3 of this Final Report. The losses were caused by Piedmont's selling of put options during a declining price market, requiring the Company to close its positions at prices higher than market.

5.2.9 How do losses incurred compare to losses of comparable utilities and to losses incurred in Piedmont's hedging plans in other states?

The hedging losses were lower in Tennessee than in North and South Carolina due to the fact that sales volumes in Tennessee were lower and Tennessee hedging expenditures are limited to 1 percent of actual purchased gas costs. The Company reported losses of $176.2 million in North Carolina and $32.0 million in South Carolina. These compare to losses of $13.2 million in Tennessee.

Data related to hedging results for other utilities is not always publicly available and is frequently confidential. However, Exeter found publicly available data for a sample of other gas utilities.

UGI Utilities, Inc. - Gas Division ("UGI"), a Pennsylvania Utility, operated a hedging program for the purchase of gas supplies it injected into storage during the summer using forward fixed price purchases. During the three-year period 2008-2010, UGI's losses totaled $93.5 million. UGI's annual sales are approximately 28,000,000 Mcf and annual fixed price purchases averaged 17,250,000 Dth.

Columbia Gas of Ohio, Inc. ("Columbia") operated a hedging program using forward fixed price purchases for a portion of its winter period gas supplies. During the winter of 2008-2009, Columbia fixed prices on approximately 12,750,000 Dth and sustained losses of approximately $31 million. For the winter of 2009-2010, Columbia fixed prices on approximately 13,150,000 Dth and sustained losses of nearly $40 million. Columbia's annual average sales volumes are approximately 80,000,000 Mcf.

Northern Indiana Public Service Company ("NIPSCO") operated a hedging program using forward fixed price purchases for approximately 20 percent of its flowing winter period gas supplies. During the winter of 2008-2009, NIPSCO sustained losses of nearly $30 million, losses were $7.7 million for the winter of 2009-2010 and $15.3 million for the winter of 2010-2011. NIPSCO's annual sales volumes are approximately 72,000,000 Mcf.

5.2.10 Overall assessment of the operation, performance and results of Piedmont's hedging plan.

Exeter's overall assessment of Piedmont's hedging plan is discussed in Section 5.3 of this Final Report.

5.3 Results and Conclusions

Piedmont adhered to the hedging activities approved under the Plan during the review period. 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. Generally, the goal of hedging is to, over time, mitigate price volatility. However, Piedmont has taken a conservative approach to hedging, electing to use hedging to provide a degree of disaster protection in the case of unexpected fly-ups in gas prices.

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.

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 [redacted] sales and transportation customers during the review period, and throughput averaged [redacted] Dth;
- 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, [redacted]
- Piedmont's ability to earn rewards under the commodity cost component of the Plan has declined due to reductions in the range of delivered gas prices attributable to factors including the development of Marcellus Shale gas supplies in the Appalachian Basin;
- [redacted]
- Piedmont operated under asset management arrangements [redacted]
- Piedmont earned a reward of [redacted] from its capacity release, asset management and off-system sales activities during the review period;
- Piedmont engaged in no transaction with affiliates during the review period;
- Piedmont's review period forecasts of design peak day demands were reasonable;
- The revised design peak day weather criterion adopted by Piedmont after the conclusion of the review period is significantly more conservative than its

review period criterion; however, the revised criterion cannot be considered unreasonable;

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

- Piedmont's review period use of a 5 percent reserve margin when viewed in conjunction with its design peak day criteria of 60.7 heating degree days was reasonable;

- Piedmont maintains excess year-round and winter season 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 reliance on year-round firm transportation capacity and increasing its reliance on winter season service arrangements; however, the availability of such opportunities are limited until 2014; and increasing its reliance on winter season service arrangements will likely reduce the revenues Piedmont is able to generate from asset management arrangements;

- 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 gas cost "savings" that would have been realized without the existence of the Plan;

- Piedmont could be improperly rewarded under the Plan if it contracted for gas supplies with first-of-the-month price purchase rights; however, Piedmont did not enter into such arrangements during the review period;

- Piedmont has the ability to determine the payment schedule for the asset management arrangement fees it received and, therefore, the potential exists for Piedmont to circumvent the $1.6 million Plan cap by adjusting the AMA payment schedule;

- Although Piedmont maintains excess year-round firm transportation capacity due to the contractual realities of the interstate pipeline capacity markets, the Plan provides incentives which are inconsistent with the goal of reducing pipeline demand charges through a greater reliance on winter season services. However, after the conclusion of the review period, Piedmont did reduce its reliance on year-round firm transportation capacity and increase its reliance on winter season services;

- 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 has adversely impacted the Company's sales customers. It would not be unreasonable to deny Piedmont its share of the margins from off-system sales which were made during and after May 2009 when current daily spot market prices were higher than first-of-the-month prices; and

- 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.

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:

$$I = F_f(P_0K_{0+P_1K_1}+P_cK_c+...P_\alpha K_\alpha) +F_0O+F_dD; \text{ where}$$
$$F_f+F_0+F_d =1; \text{ and}$$

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.

Gas Supply Reservation Fees

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.

[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.

Filing with the Authority

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.