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November 12, 2015

Via Hand-Delivery
and Email

The Honorable Earl Taylor
Executive Director
Tennessee Regulatory Authority
c/o Sharla Dillon
502 Deaderick Street, Fourth Floor
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 October 2015, 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.

This material is also being filed by way of email to the Tennessee Regulatory Authority Docket Manager, Sharla Dillon. Please file the original and four copies of this filing and stamp the additional copy as "filed." Then please return the stamped copies to me by way of our courier.

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

With kindest regards, I remain

Very truly yours,

R. D. Grimes

R. Dale Grimes

Enclosure

REDACTED REPORT

REDACTED

CONFIDENTIAL

Final Report

PIEDMONT NATURAL GAS COMPANY

AUDIT STAFF OF THE TENNESSEE REGULATORY AUTHORITY

CONSUMER ADVOCATE DIVISION OF THE TENNESSEE ATTORNEY GENERAL

REVIEW OF PERFORMANCE INCENTIVE PLAN

AND CAPACITY RESOURCES

Piedmont Natural Gas

OCTOBER 2015

Prepared by:

EXETER
ASSOCIATES, INC.
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Columbia, Maryland 21044

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1.0 INTRODUCTION

Piedmont Natural Gas Company (Piedmont or Company) is a North Carolina corporation with its headquarters located in Charlotte. The Company is principally engaged in the natural gas distribution business. Piedmont serves over one million customers, including over 170,000 in Tennessee; 725,000 in North Carolina; and 135,000 in South Carolina. The gas procurement function at Piedmont is performed jointly for all three service territories by the corporate Gas Supply Department.

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 (Plan) for Nashville Gas Company, the predecessor to 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, the Settling Parties) filed a Settlement Agreement (2007 Settlement) which was approved by the TRA effective December 14, 2007.

The 2007 Settlement, among other things, provided for triennial reviews of Piedmont's activities under the Plan by an independent consultant. The purpose of the independent reviews 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) has been selected through an RFP process by the Settling Parties to perform the independent review envisioned under the 2007 Settlement for the period July 1, 2011 through June 30, 2014 (review period). Exeter was previously selected to perform the first triennial independent review provided for under the 2007 Settlement that covered the period July 1, 2008 through June 30, 2011, and to perform an independent review for the period July 1, 2006 through June 30, 2008.

A Draft Report presenting the findings, results, and conclusions of Exeter's current review was provided to the Settling Parties on September 25, 2015. On October 10, 2015, 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. Exeter has incorporated the Company's comments into this final report (Report), as Exeter deemed appropriate.

Exeter's Report consists of eight sections in addition to this introductory section. Section 2 of the Report identifies the interstate pipelines serving Piedmont as well as the services the Company purchases from each pipeline. Included in Section 2 is a summary of the Company's Asset Management Agreements (AMAs) which existed during the review period. Section 2 also provides a description of the Piedmont system and the markets it serves.

Section 3 of the Report summarizes each component of the Plan 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 the Report evaluates Piedmont's storage management activities. Section 5 of the Report reviews and examines the design peak day, winter season, and annual capacity resources, or entitlements, available to meet customer demands; assesses the manner in which Piedmont forecasts the design day demands of its customers; and evaluates whether Piedmont maintains a reasonable balance between its capacity entitlements and the anticipated demands of its customers. Section 5 evaluates the design day criteria selected by Piedmont for capacity planning purposes and identifies actual winter season peak day demands experienced during the review period. This section includes 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. Section 5 also includes a discussion of potential modifications to Piedmont's interstate pipeline capacity portfolio.

Section 6 of the Report summarizes and evaluates Piedmont's hedging activities. Section 7 begins with a comparison of Piedmont's Plan with the performance-based gas procurement incentive mechanisms of Chattanooga Gas Company (Chattanooga Gas) and Atmos Energy Corporation (Atmos), two Tennessee natural gas utilities which also operate under gas cost incentive mechanisms. This is followed by an evaluation of the balance of incentives between sales customers and Piedmont under the Plan. Piedmont's Gas Supply Incentive Compensation Program is also evaluated in Section 7.

The final section of the Report summarizes Exeter's conclusions, includes findings of fact, and identifies and describes areas of concern and improvement that may warrant further consideration.

2.0 PIEDMONT SYSTEM AND MARKETS

Piedmont provides natural gas sales and distribution service to the Nashville, Tennessee metropolitan area. Piedmont purchased services from five interstate pipelines during the review period: Columbia Gas Transmission (Columbia Gas), Columbia Gulf Transmission (Columbia Gulf), Midwestern Gas Transmission (Midwestern or MGT), Tennessee Gas Pipeline (TGP), and Texas Eastern Transmission (Texas Eastern). Of these five interstate pipelines, Piedmont is interconnected to three: Columbia Gulf, TGP, and Texas Eastern. Piedmont is also interconnected with East Tennessee Natural Gas (ETNG); however, the Company does not purchase any services directly from ETNG. Piedmont's interstate pipeline 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 Section 2.1. Table 2 summarizes the services available to meet customer demands for the winter of 2013-2014. This information is provided to assist in understanding the various components of the Plan, evaluating Piedmont's compliance with the Plan, and evaluating the reasonableness of Piedmont's capacity resources.

2.1 Interstate Pipeline Transportation Services

Piedmont's transportation arrangements with Columbia Gulf, TGP, and Texas Eastern provide for the delivery of gas supplies directly to Piedmont's system. As subsequently explained, although Piedmont is not directly interconnected with Columbia Gas, the Company's storage 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 TGP, ETNG, 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 TGP, to the northern portion of Piedmont's system by ETNG, and to the east side of Piedmont's system by Columbia Gulf. The Company's Midwestern-sourced delivery arrangements are discussed in greater detail later in Section 2.1.4. Although Piedmont's distribution system is supplied by Columbia Gulf, TGP, Texas Eastern, and ETNG, the distribution systems "behind the meters" served by each pipeline are generally operated as independent systems. Customers located on the western side of Piedmont's distribution system are generally supplied with gas delivered by TGP; customers located on the eastern and southern portions of the system are generally served with gas delivered by Columbia Gulf and Texas Eastern; and customers located on the northern portion of the system are generally served by ETNG.

REDACTED

Table 1. PIEDMONT NATURAL GAS COMPANY Summary of Interstate Pipeline Interconnects							
	Pipeline	Percent of Peak Day	Meter Number(s)	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.	Columbia Gulf		4241	Ultrasonic (10)	Southern portion of Nashville distribution system	Davidson	Nashville
5.	Texas Eastern		70316	Turbine	City of Hartsville distribution system	Trousdale	Hartsville
6.	Texas Eastern		73423	Ultrasonic (6)	Southeastern portion of Nashville distribution system	Rutherford	Nashville
7.	Tennessee Gas Pipeline		020280-01	Rotary	City of Greenbrier distribution system	Robertson	City of Greenbrier
8.	Tennessee Gas Pipeline		020309-01	4" Sr Orifice Tube	Ashland City distribution system	Cheatham	Ashland City
9.	Tennessee Gas Pipeline		020312-0, 020312-A	Ultrasonic (12)	Main portions of Nashville distribution system	Davidson	Nashville
10.	Tennessee Gas Pipeline		020600-01	Turbine	City of White House distribution system	Robertson	White House
11.	Tennessee Gas Pipeline		020610-0	Rotary (2)	City of Fairview distribution system	Dickson	Fairview
12.	Tennessee Gas Pipeline		020846-0	Rotary (3M)	Cheatham County Industrial Park	Cheatham	Ashland City
13.	Tennessee Gas Pipeline		20753-0	Rotary (1M)	Robertson County outside city limits of Greenbrier and White House	Robertson	Outside Greenbrier City Limits
14.	East Tennessee Natural Gas		59218	Ultrasonic (4)	Northern portions of Nashville distribution system	Sumner	Sumner

Figure 1.
Piedmont Service Territory and Pipeline Interconnects

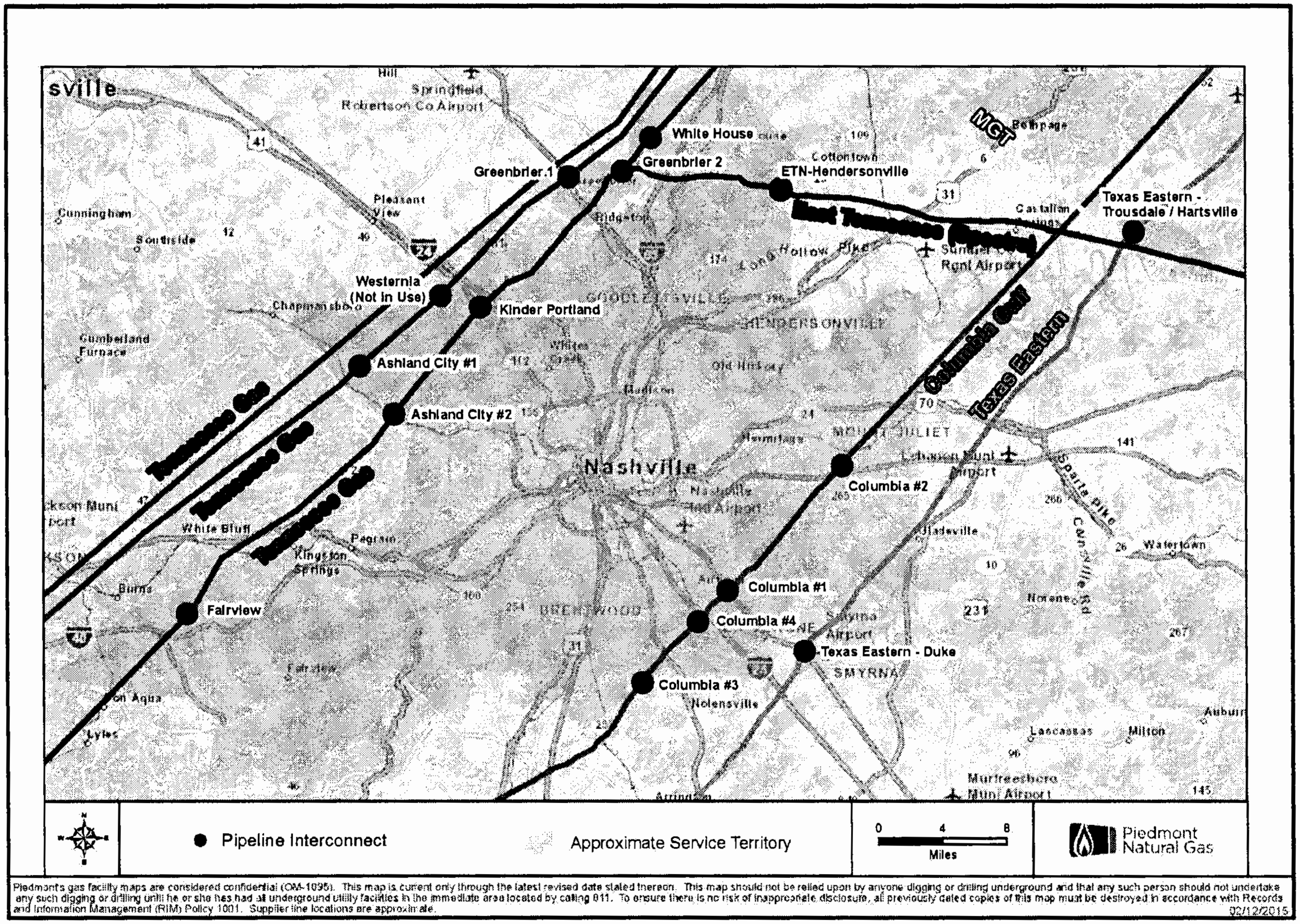

Table 2.
PIEDMONT NATURAL GAS COMPANY
Summary of Design Day Capacity Contracts
(2013-2014 Winter Season)

Pipeline – Service	Contract No.	MDQ (Dth) Winter	MDQ (Dth) Summer	Available Quantity (Dth) Winter Season	Available Quantity (Dth) Annual	Contract Expiration
Columbia Gas						
Storage Service (FSS/SST)[1]	38017/38052	10,000	5,000	611,870	0	3/31/2024
Columbia Gulf						
Firm Transportation (FTS-1)[1]	43462	10,000	9,202	1,510,000	3,479,228	10/31/2022
Firm Transportation (FTS-1)[1]	14252	31,000	11,755	4,681,000	7,196,570	10/31/2018
Firm Transportation (BH)[1]	43462/14252	41,000	20,957	6,191,000	10,675,798	--
Midwestern Gas Transmission						
Firm Transportation (FT-A)	FA0342	100,000	100,000	15,100,000	36,500,000	01/06/2023
Firm Transportation (FT-B)[1]	FB0006	100,000	100,000	15,100,000	36,500,000	01/06/2023
Tennessee Gas Pipeline						
Firm Transportation (FT-A)[1]	237	74,100	74,100	11,189,100	27,046,500	10/31/2014
Storage Service (FS-MA/FT-BH)[1]	6815/46715	49,828	0	2,901,943	0	10/31/2019
Storage Service (FS-PA/FT-BH)[1]	2400/46715	6,072	0	672,091	0	10/31/2019
Firm Transportation (FT-BH)	46715	26,000	0	0	0	10/31/2014
Texas Eastern Transmission						
Firm Transportation (FT-1)[1]	910473	10,000	0	1,510,000	1,510,000	03/31/2019
Firm Transportation (SCT)[1]	800059	1,677	1,677	84,409	204,035	10/31/2014
Piedmont LNG[1]	[redacted]					None
Total Citygate Capacity Resources		[redacted]				

MDQ = maximum daily delivery quantity; Dth = dekatherms; LNG = liquefied natural gas
Note: [1] Citygate Capacity Resource

2.1.1 Columbia Gas Transmission

Piedmont purchased unbundled firm storage transportation service from Columbia Gas under Rate Schedule SST during the review period. 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. The maximum daily delivery quantity (MDQ) under Piedmont's SST arrangement is 10,000 dekatherms (Dth) per day during the months of October through March and 5,000 Dth per day during the months of April through September. 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 a lease agreement between the two pipelines (FERC Docket No. CP13-480). 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 firm transportation service from Columbia Gulf under three Rate Schedule FTS-1 arrangements during the review period that provided for the delivery of Gulf Coast-sourced gas supplies directly to Piedmont's system. Contract No. 76812 initially 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). Effective November 1, 2012, the winter period capacity under Contract No. 43462 was increased to 10,000 Dth per day and the summer period MDQ was increased to 9,601 Dth per day. Contract No. 76812 was allowed to expire and was terminated by Piedmont effective October 31, 2013. Effective December 1, 2013, Piedmont entered into a third FTS-1 contract with Columbia Gulf (Contract No. 14252) with an MDQ of 31,000 Dth per day during the winter period and an MDQ of 11,755 Dth per day during the summer period. The capacity under Piedmont's Columbia Gulf FTS-1 arrangements can be segmented to deliver Gulf Coast production area sourced supplies and, at the same time by backhaul, gas supplies sourced on Columbia Gas. For the winter of 2013-2014, Piedmont's FTS-1 arrangements provided the Company with 41,000 Dth of backhaul capacity. In addition to its firm transportation agreements with Columbia Gulf, Piedmont also maintained an interruptible transportation (IT) arrangement that provided for the backhaul delivery of gas to Piedmont from an interconnect with Midwestern at Walnut Gove, Tennessee.

2.1.3 Tennessee Gas Pipeline

The TGP system originates in the Texas and Louisiana natural gas production regions and extends to New England. In the production region, the TGP system consists of three primary transmission lines, referred to as the 100, 500, and 800 Legs. The TGP system is also divided into eight zones for rate purposes (Zones 0, L, and 1-6). The State of Texas is designated as Zone 0, Zone L consists largely of the State of Louisiana, and Zone 1 extends from the Texas border with Louisiana to the Kentucky/Tennessee border. During the review period, Piedmont purchased firm transportation service from TGP 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 (Dth)**
Zone 0 – 100 Leg	22,435
Zone L – 500 Leg	28,204
Zone L – 800 Leg	23,461
TOTAL	**74,100**

Piedmont also purchased a discounted rate transportation service from TGP under Contract No. 46715 (Rate Schedule FT-BH). This contract is a backhaul transportation arrangement that provides for the delivery of up to 55,900 Dth per day from Piedmont's Market and Production area storage accounts, as well as from TGP's 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, after accounting for the 55,900 Dth from TGP storage. For the winter of 2013-2014, this 26,000 Dth per day was not a design day capacity resource but enabled Piedmont to satisfy hourly firm demand swings when TGP requires uniform hourly takes.

2.1.4 Midwestern Gas Transmission

Effective November 2007, Piedmont contracted for 20,000 Dth per day of capacity with Midwestern. This arrangement provided for the upstream delivery of gas from the Chicago market area to Midwestern's TGP interconnect at Portland, Tennessee, with final delivery effectuated to the west side of Piedmont's system by TGP. 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 and ETNG at Boat Dock, Tennessee. Midwestern-sourced gas supplies can be delivered to the west side of Piedmont's distribution system by TGP (referred to as "MGT West via TGP"), to the northern portion of Piedmont's distribution system by ETNG, and to the east side of Piedmont's distribution system by Columbia Gulf. Midwestern Contract No. FA0342 provides for the firm upstream transportation of up to 100,000 Dth per day from an interconnect with ANR Pipeline in Joliet, Illinois near the Chicago area to an interconnect with TGP at Portland, Tennessee. Midwestern Contract No. FB0006 provides for the firm upstream transportation of up to 75,000 Dth per day from Portland, Tennessee to an interconnect with Columbia Gulf at Walnut Grove, Tennessee (referred to as "MGT East via Gulf to Walnut Grove"), and up to 25,000 Dth per day to an interconnect with ETNG at Boat Dock in Sumner, Tennessee (referred to as "MGT East via ETNG to Boat Dock"). Deliveries by Midwestern under Contract Nos. FA0342 and FB0006 to TGP, Columbia Gulf, and ETNG are made by backhaul on TGP, Columbia Gulf, and ETNG. Deliveries to Piedmont from Walnut Grove are made under FT and IT arrangements with Columbia Gulf, and deliveries from Boat Dock are made by backhaul utilizing capacity reserved by the Company's Carolina service territories when the capacity has not been released to a third party (See Section 2.1.6). If the capacity has been released to a third party, deliveries from Boat Dock must be made by via backhaul utilizing an ETNG IT contract.

Since Piedmont is not directly interconnected with Midwestern, Midwestern-sourced gas supplies are delivered to Piedmont by other pipelines (TGP, Columbia Gulf, and ETNG). Multiple options exist for the delivery of Midwestern-sourced gas supplies to Piedmont. In addition, during the summer months of the review period, Piedmont's AMAs limited the quantities of Midwestern-sourced gas available on a daily basis. These limits varied by month and year. Piedmont believed that reducing the available daily quantities of Midwestern-sourced gas during the summer increased the fee that it received under its AMAs. Table 3 summarizes the various Midwestern delivery paths and MDQs included under the Plan during the review period. These Midwestern delivery paths and MDQs are discussed further in Section 3.1.3.

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Table 3.
PIEDMONT NATURAL GAS COMPANY
Summary of Midwestern Delivery Paths and Maximum Daily Contract Quantities
(July 2011 – June 2014)
(Dth)

Month/Year	West Side via TGP	North Side via ETNG	East Side via Columbia Gulf	TOTAL
July 2011	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]
January 2012	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]
April	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]
January 2013	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]
April	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]
January 2014	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]
April	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]

2.1.5 Texas Eastern Transmission

Piedmont purchased firm transportation service from Texas Eastern under two different rate schedules during the review period. The Company 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 of these Texas Eastern transportation arrangements to acquire Gulf Coast-sourced gas supplies. Rate Schedule SCT capacity, used to serve the City of Hartsville, Tennessee, is excluded from the subsequently discussed commodity procurement cost component of the Plan.

2.1.6 East Tennessee Natural Gas

Piedmont's Tennessee service territory does not purchase firm transportation or storage service directly from ETNG; however, firm transportation service is purchased by Piedmont's Carolina service territories under Rate Schedule FT-A. The demand charges associated with the Carolina FT-A contract are recovered entirely from Piedmont's customers in the Carolinas. On occasion, Piedmont Tennessee uses the ETNG FT-A contract to deliver Midwestern-sourced gas from Boat Dock on a segmented backhaul basis to its Hendersonville interconnect with ETNG. When this occurs, Piedmont assigned the variable charges associated with the segmented backhaul delivery to its Nashville service territory. The Carolina service territory's ETNG transportation contract has been released to a third party since November 1, 2012. Therefore, Piedmont's Tennessee territory can no longer utilize this contract for a segmented backhaul, and deliveries from Boat Dock must be made by via backhaul utilizing an ETNG IT contract.

2.2 Interstate Pipeline and On-system Storage

Piedmont purchased contract storage service from Columbia Gas and TGP during the review period. These arrangements are further described below. 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 arrangement with Columbia Gas. The maximum daily withdrawal quantity (MDWQ) under Piedmont's FSS arrangement is 10,000 Dth per day and the maximum seasonal storage quantity (MSQ) is 611,871 Dth.

2.2.2 Tennessee Gas Pipeline

During the review period, Piedmont purchased unbundled market-area firm storage service from TGP under Rate Schedule FS-MA and unbundled production-area firm storage service under Rate Schedule FS-PA. Gas delivered to both market- and production-area storage is primarily sourced on TGP and purchased in the Gulf Coast production region. Deliveries to Piedmont's system from market- and production-area storage are nominated at TGP's Portland, Tennessee station. Gas from storage is delivered to Piedmont by backhaul under FT-BH Contract No. 46715. The MDWQs under the FS-MA and FS-PA arrangements are 49,828 Dth and 6,072 Dth per day, respectively. The MSQs are 2,901,943 Dth and 672,091 Dth, respectively.

2.2.3 Liquefied Natural Gas

Piedmont operates an on-system LNG facility. During the prior triennial review period, the maximum LNG facility capability was [redacted] Dth per day. Prior to the winter of 2011-2012, Piedmont reassessed the takeaway capacity from the LNG facility and determined that the maximum takeaway capacity on a design day was [redacted] Dth per day. The LNG facility can produce at maximum levels for approximately 12 days. For the winters of 2012-2013 and 2013-2014, the maximum production capability of the LNG facility was rated at [redacted] Dth and [redacted] Dth per day, respectively, due to technical issues associated with liquefaction of gas supplies. The maximum takeaway capacity of Piedmont's LNG facility was restored to [redacted] Dth per day for the winter of 2014-2015.

2.3 Delivered Services

As a result of a design day capacity deficiency projected for the winter of 2011-2012, Piedmont acquired a [redacted] delivered-to-citygate peaking service from [redacted] or [redacted] Dth per day. This supply was deliverable by Texas Eastern and priced based on [redacted].[1] As a result of the previously discussed reduction in deliverability from Piedmont's LNG facility for the winter of 2012-2013, Piedmont acquired a [redacted], delivered-to-citygate peaking service for [redacted] Dth per day from [redacted]. These supplies were deliverable by TGP and priced based on [redacted]

[redacted]

[redacted].

For the period November 2013 through October 2014, Piedmont contracted for a delivered-to-citygate supply service of [redacted] Dth per day with [redacted] These supplies were deliverable by Columbia Gulf. [redacted] and the commodity price was based on [redacted]

To address the reduction in LNG deliverability for the 2013-2014 winter season, Piedmont contracted for a delivered-to-citygate supply service of [redacted] Dth per day from [redacted]. These supplies were deliverable by Columbia Gulf. [redacted] and provided for a commodity price based on [redacted].

2.4 Post-Review Period Capacity Portfolio Changes

[redacted]

[redacted]

2.5 Asset Management Agreements

Piedmont operated under AMAs during the entire review period. Each AMA was awarded through an RFP process. Under the AMA's, Piedmont released all of its interstate pipeline transportation and storage capacity to the AMA service provider, or Asset Manager. Piedmont also assigned or made available to the Asset Manager all of its gas supply contracts other than its citygate delivered supply contracts. Piedmont was paid a fee under each AMA but remained responsible for all pipeline demand charges associated with the released capacity.

Under the AMAs, each day, Piedmont would determine the quantity of gas required to meet its customers' requirements by delivering pipeline and its daily storage injection and withdrawal activity, and would convey this information, referred to as virtual dispatch, to the Asset Manager. The Asset Manager was then entitled to use the capacity and gas supply assets assigned to it under the AMA, or any other assets available to the Asset Manager, to meet Piedmont's daily requirements. The Asset Manager was entitled to utilize the assigned capacity that was not required to serve Piedmont to pursue the Asset Manager's own business interests (optimization strategies). [redacted]. Table 4 summarizes Piedmont's review period AMA

[redacted]

arrangements. Under the 2011-2012 and 2012-2013 AMAs with Capital Energy Ventures (CEV), [redacted].

Table 4.
PIEDMONT NATURAL GAS COMPANY
Asset Management Agreements

Manager	Term	Annual Fee
Capitol Energy Ventures	November 1, 2010 – October 31, 2011	[redacted]
Capitol Energy Ventures	November 1, 2011 – October 31, 2012	
Capitol Energy Ventures	November 1, 2012 – October 31, 2013	
Tenaska Marketing Ventures	November 1, 2013 – October 31, 2014	
[redacted]		

2.6 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 5 summarizes the number of customers served and annual throughput by service class for 2012, 2013, and 2014.

Table 5. PIEDMONT NATURAL GAS COMPANY Annual Customers and Volumes by Class (12 Months Ended March)			
Customers by Class	**2012**	**2013**	**2014**
Residential Sales	[redacted]		
Small General Sales			
Medium General Sales			
Firm Industrial Sales			
Interruptible Industrial Sales			
Natural Gas Vehicle Sales			
Sales for Resale			
Subtotal Sales			
Firm Transportation			
Interruptible Transportation			
Special Contract Transportation			
Subtotal Transportation			
TOTAL			
Volumes by Class (Dth)	**2012**	**2013**	**2014**
Residential Sales	[redacted]		
Small General Sales			
Medium General Sales			
Firm Industrial Sales			
Interruptible Industrial Sales			
Natural Gas Vehicle Sales			
Sales for Resale			
Subtotal Sales			
Firm Transportation			
Interruptible Transportation			
Special Contract Transportation			
Subtotal Transportation			
TOTAL			
Note: Excludes off-system sales.			

3.0 PERFORMANCE INCENTIVE PLAN

This section of Exeter's 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, as amended in Piedmont's review period base rate case in Docket No. 11-00144, is included as Appendix A to this Report. The amendments to the Plan adopted in Docket No. 11-00144 are shown in redline in Appendix A. Piedmont files quarterly and an annual Performance Incentive Plan report with the TRA for each plan year. TRA Staff audits each Annual Plan Report and presents its findings in an annual Compliance Audit Report (Audit Report). TRA Staff's Audit Reports during the review period identified no material findings. Table 6 summarizes Piedmont's performance under the Plan for the review period. Additional detail concerning Piedmont's activities and performance under the Plan is subsequently presented in this section.

Table 6.
PIEDMONT NATURAL GAS COMPANY
Performance Incentive Plan – Summary of Review Period Results

	Gain/(Loss)		
Plan Year	Ratepayers	Company	Total Savings
July 2011 – June 2012	[redacted]		
July 2012 – June 2013			
July 2013 – June 2014			
TOTAL			

3.1 Commodity Procurement Cost Component

3.1.1 Background and Description

In the natural gas industry there are generally two types of physical gas supply purchase arrangements: first-of-the-month monthly baseload (monthly) purchases and daily purchases. Monthly purchases are generally arranged several days prior to the month of delivery, commence flow on the first day of the month, and provide for the delivery of the same quantity of gas on each day during the month. Daily purchases are arranged on the business day prior to delivery. While daily purchases typically flow for one day, these purchases may also be arranged for multiple consecutive days such as for weekends (Friday-Monday) and holidays.

There are various natural gas industry publications that identify, after the fact, the average price paid for monthly and daily gas purchases at major natural gas trading locations.

These average, or market, prices are referred to as index prices. Monthly index prices are published in *Inside FERC's Gas Market Report* (*Inside FERC*) and *Natural Gas Intelligence (NGI)*. Daily index prices are published in *Gas Daily*. Trading locations at which Piedmont purchases gas with published index prices include the following:

Columbia Gulf Transmission

- Rayne (Louisiana) or Mainline

Midwestern Gas Transmission

- Chicago Citygate

Tennessee Gas Pipeline

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

Texas Eastern

- East Louisiana (ELA)

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. 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. Gas supplies may be delivered to Piedmont's system under firm or interruptible transportation arrangements or purchased on a delivered-to-citygate basis. If Piedmont's actual monthly costs exceed benchmark costs, 25 percent of the difference is assessed to Piedmont, and sales customers' gas costs are reduced by the amount assessed to Piedmont. If benchmark costs exceed actual monthly costs, 25 percent of the difference is retained by Piedmont, and sales customers' gas costs are increased by the amount retained by Piedmont.

The monthly benchmark cost 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 different benchmarking procedures for monthly and daily purchases delivered under Piedmont's firm interstate pipeline transportation arrangements, and for other purchases, which would include purchases delivered from the receipt point purchase location to Piedmont's citygate under interruptible transportation arrangements. The benchmark price for each type of purchase is weighted by actual purchases made during a month to derive the MBIP.

For the benchmarking of monthly purchases, a delivered-to-citygate price is first calculated for each geographic receipt point location accessed by Piedmont's firm, and as applicable, interruptible transportation arrangements, based on the applicable monthly 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 and serves as the benchmark for monthly purchases.

For the benchmarking of daily purchases, each of Piedmont's actual daily purchases is priced at the applicable daily index price, plus the applicable fuel and variable firm, and as applicable, interruptible transportation charges. The delivered costs for each purchase are totaled and divided by the actual quantity of daily purchases to derive the daily purchase benchmark included in the MBIP.

During the review period, all of Piedmont's other purchases were citygate purchases. Piedmont's citygate purchases were typically made to displace the purchase of supplies that would have been delivered under firm transportation arrangements. The tariff language describing the Plan does not appear to specifically address the benchmarking of citygate purchases when used to displace deliveries under firm transportation arrangements. The calculation of the benchmark price used by Piedmont during the review period was dependent upon the specific type of citygate purchase. Those citygate purchases priced based on a production area commodity index price were benchmarked based on the applicable production area index price plus the maximum applicable interruptible transportation and variable fuel charges for the interstate pipeline delivering the gas to Piedmont's citygate. Those citygate purchases which were priced based on a delivered-to-citygate price were benchmarked based on the citygate delivered cost of the supplies that were displaced by the citygate purchases. The benchmark costs for each citygate purchase were totaled and divided by the actual quantity of citygate purchases to derive the other purchase benchmark reflected in the MBIP.

Shown in Table 7 for illustrative purposes is the calculation of the MBIP for March 2014. Also shown are the commodity procurement cost gains and losses. Section I of Table 7 shows the calculation of the monthly purchase benchmark included in the MBIP. Column C of Section I identifies Piedmont capacity entitlements by purchase location. Column D of Section I identifies the percentage share of total capacity for each purchase location. Column E identifies the delivered cost of gas sourced under each transportation arrangement based on the applicable published monthly index price. Column F calculates the monthly component of the MBIP. As shown there, the benchmark price against which Piedmont's monthly purchases were compared under the Plan was [redacted] per Dth (line 9, Column F) in March 2014.

Table 7.
PIEDMONT NATURAL GAS COMPANY
Summary of Monthly Benchmark Index Price Calculation and Commodity Procurement Incentive Gains/(Losses)
(March 2014)

I. Purchase Location – Contractual Capacity	Actual FOM Purchases (Dth/Day) (A)	Actual FOM Purchases Percent (B)	Pipeline Capacity (Dth/Day) (C)	Pipeline Capacity Percent (D)	Delivered Price ($/Dth) (E)	Weighted Price ($/Dth) (F)
1. TGP Zone 0 – 100 Leg	[redacted]					
2. TGP Zone 1 – 500 Leg						
3. TGP Zone 1 – 800 Leg						
4. Columbia Gulf FTS-1						
5. Texas Eastern FT-1						
6. Midwestern East Side via Columbia Gulf – First 41,000						
7. Midwestern East via Columbia Gulf – Next 50,000						
8. Midwestern East via ETNG – Hendersonville						
9. TOTAL						

II. Components of Monthly Benchmark Index Price	Actual Purchases Dth (A)	Actual Purchases Percent (B)	Component Benchmark ($/Dth) (C)	Weighted Component Benchmark ($/Dth) (D)	Monthly Benchmark (E)
1. Monthly Purchases	[redacted]				
2. Daily Purchases					
3. Citygate Purchases					
4. Purchases/Monthly Benchmark Index Price					
5. Actual Costs					
6. Gain/(Loss) Based on MBIP					

III. Commodity Procurement Gain/(Losses) by Component	Actual Purchases (Dth) (A)	Component Benchmark ($/Dth) (B)	Actual Cost ($/Dth) (C)	Unit Gain/ (Loss) ($/Dth) (D)	Total Savings/(Loss) (E)
1. Monthly Purchases	[redacted]				
2. Daily Purchases					
3. Citygate Purchases					
4. Purchases Gain/(Loss)					

Section II shows the calculation of the combined MBIP based on the individual monthly, daily, and citygate purchase benchmarks. Due to the extensive detail, calculations of the daily and citygate benchmarks included in the MBIP are only summarized in Table 7 (Section II, lines 2 and 3). The daily and citygate benchmarks included in the MBIP are calculated as previously described. As shown on lines 2 and 3 in Column C of Section II, the daily and citygate purchase benchmarks were [redacted] per Dth and [redacted] per Dth, respectively. As shown on line 4 in Column D of Section II, the total MBIP is [redacted] per Dth. Under the Plan, Piedmont's total purchases during March 2014 of [redacted] Dth were multiplied by the MBIP of [redacted] per Dth to calculate total benchmark costs of [redacted] (line 4, Column E). As shown on line 5 in Column E, the actual costs associated with Piedmont's purchases of [redacted] Dth were [redacted], resulting in incentive Plan [redacted] (line 6, Column E).

Section III of Table 7 "unbundles" the MBIP and identifies incentive Plan [redacted] by type of purchase. As shown there, monthly purchase incentive Plan [redacted] (line 1, Column E), and citygate purchase incentive Plan [redacted] (line 3, Column E). [redacted] (line 2, Column E).

3.1.2 Review Period Gas Procurement Activity

Firm Transportation Delivered Supplies. Table 8 provides a comparison of monthly *Inside FERC* and *NGI* index prices adjusted for the applicable pipeline variable and fuel charges for the locations at which Piedmont could have purchased gas using its firm transportation capacity during the review period.[3] That is, the prices in Table 8 reflect the effective delivered variable cost for purchases that could have been made at these various purchase locations. As indicated previously, index prices are published after trading for a location has concluded. Therefore, while market participants will have a close estimate of an index price during the trading period, the precise index price will not be known until it is published. As indicated by the prices identified in Table 8, TGP Zone 0 – 100 Leg sourced supplies were generally Piedmont's lowest-cost TGP delivered supplies during the review period, followed by TGP Zone L – 800 Leg sourced supplies. The TGP Zone 0 – 100 Leg sourced supplies were also generally slightly less expensive than Columbia Gulf sourced supplies and comparably priced with Texas Eastern sourced supplies. TGP Zone L – 500 Leg sourced supplies were generally the highest-cost Gulf Coast production area supplies. Table 8 reveals that Midwestern sourced supplies consistently had a higher delivered cost than Gulf Coast production area supplies.

Table 9 identifies Piedmont's review period monthly purchases by location, and reveals that for TGP sourced supplies, [redacted]

[3] Under the Plan, monthly Midwestern purchases are benchmarked based on *NGI* index prices. All other monthly purchases are benchmarked based on *Inside FERC* index prices.

Table 8. PIEDMONT NATURAL GAS COMPANY Review Period First-of-the-Month Delivered Index Prices ($/Dth)						
	Tennessee Gas Pipeline			Columbia Gulf	Texas Eastern	Midwestern
Month/Year	**Z0-100**	**ZL-500**	**ZL-800**	**Rayne**	**ELA(2)**	**Chicago(1)**
July 2011	$4.3507	$4.4337	$4.4236	$4.3893	N/A	$4.4590
August	4.3608	4.4135	4.4236	4.4096	N/A	4.5706
September	3.9048	3.9086	3.8985	3.8909	N/A	4.0334
October	3.7628	3.7672	3.7773	3.7484	N/A	3.9926
November	3.4904	3.5417	3.5518	3.5349	$3.4646	3.8947
December	3.3587	3.4105	3.3802	3.3620	3.3338	3.7832
January 2012	3.0952	3.1379	3.1076	3.0772	3.0628	3.3676
February	2.6088	2.7340	2.6633	2.6874	2.6212	2.8203
March	2.4568	2.4816	2.4916	2.4535	2.4406	2.6379
April	2.1375	2.1831	2.1730	2.1469	N/A	2.2040
May	2.0056	2.0517	2.0213	2.0250	N/A	2.1330
June	2.4623	2.4359	2.4965	2.4111	N/A	2.6503
Winter Average	**$3.0020**	**$3.0611**	**$3.0389**	**$3.0230**	**$2.9846**	**$3.3007**
Annual Average	**$3.1662**	**$3.2083**	**$3.2007**	**$3.1780**	**$2.9846**	**$3.3789**
July 2012	$2.7566	$2.7696	$2.7493	$2.7567	N/A	$2.8429
August	3.0610	3.0324	3.0628	3.0209	N/A	3.2283
September	2.6043	2.6381	2.6078	2.6042	N/A	2.8125
October	2.9088	3.0527	3.0122	2.9904	N/A	3.2283
November	3.4162	3.4976	3.4268	3.4783	$3.4442	3.8458
December	3.6902	3.6897	3.7200	3.7425	3.6765	4.1196
January 2013	3.3553	3.4066	3.3863	3.3766	3.3251	3.6937
February	3.2234	3.2751	3.2347	3.2547	3.1946	3.6125
March	3.4263	3.4470	3.4470	3.4478	3.3954	3.7140
April	3.9918	4.0497	4.0193	4.0262	N/A	4.2421
May	4.1952	4.3333	4.2016	4.1990	N/A	4.4044
June	4.1647	4.2421	4.1915	4.1786	N/A	4.3334
Winter Average	**$3.4223**	**$3.4632**	**$3.4430**	**$3.4600**	**$3.4072**	**$3.7971**
Annual Average	**$3.3995**	**$3.4528**	**$3.4216**	**$3.4230**	**$3.4072**	**$3.6731**
July 2013	$3.6969	$3.7762	$3.7357	$3.7214	N/A	$3.8162
August	3.4427	3.4825	3.4724	3.4674	N/A	3.6844
September	3.5444	3.5838	3.5737	3.5690	N/A	3.6945
October	3.4929	3.5224	3.5123	3.5176	N/A	3.7034
November	3.4929	3.5325	3.5123	3.5177	$3.4851	3.9254
December	3.7675	3.8263	3.7959	3.8014	3.7481	4.0673
January 2014	4.3574	4.4340	4.4239	4.4093	4.3608	5.0207
February	5.3743	5.6595	5.5785	5.6048	5.5361	8.2155
March	4.7540	4.8999	4.8695	4.8956	4.8229	11.0958
April	4.5462	4.6227	4.5923	4.6052	N/A	5.1504
May	4.7496	4.8253	4.7949	4.7873	N/A	5.0389
June	4.5462	4.6430	4.6126	4.6052	N/A	4.8361
Winter Average	**$4.3492**	**$4.4704**	**$4.4360**	**$4.4446**	**$4.3906**	**$6.4649**
Annual Average	**$4.1471**	**$4.2340**	**$4.2062**	**$4.2085**	**$4.3906**	**$5.1874**

Notes:
(1) Average index price for the various Midwestern Gas Transmission delivery paths.
(2) Piedmont's Texas Eastern ELA transportation arrangement is a winter-only contract and, therefore, purchases from April-October cannot be made.

REDACTED

Table 9.
PIEDMONT NATURAL GAS COMPANY
Review Period First-of-the-Month Purchases
(Dth)

	Tennessee Gas Pipeline			Columbia Gulf	Texas Eastern	Midwestern	
Month/Year	Z0-100	Z1-500	Z1-800	Rayne	ELA	Chicago	TOTAL
July 2011	[redacted]						
August							
September							
October							
November							
December							
January 2012							
February							
March							
April							
May							
June							
Subtotal							
July 2012							
August							
September							
October							
November							
December							
January 2013							
February							
March							
April							
May							
June							
Subtotal							
July 2013							
August							
September							
October							
November							
December							
January 2014							
February							
March							
April							
May							
June							
Subtotal							
TOTAL							
PERCENT							

[redacted]. Piedmont's Texas Eastern contract was a winter-only contract. Texas Eastern and Columbia Gulf generally serve the same portions of Piedmont's distribution system. [redacted]. Exeter's review of Piedmont's monthly purchases found that these purchases were consistent with least-cost procurement.

Table 10 identifies Piedmont's total purchases (monthly and daily) that were delivered under firm and interruptible transportation arrangements during the review period. Due to the extensive amount of data, daily delivered prices for each transportation arrangement are not provided; however, these prices exhibited the same relative relationship by location as monthly delivered prices. Overall, Piedmont attempted to maximize the purchase of lower-cost supplies under its firm and interruptible transportation arrangements. Exeter's review of Piedmont's purchases delivered under firm and interruptible transportation arrangements did not find any evidence that these purchases were inconsistent with least-cost procurement.

Citygate Delivered Supplies. Table 11 summarizes Piedmont's citygate purchase quantities and prices during the review period. [redacted]. This increase in citygate purchases is subsequently discussed in detail in Section 3.1.3.

REDACTED

Table 10.
PIEDMONT NATURAL GAS COMPANY
Review Period Purchases Delivered Under Firm Transportation Arrangements
(Dth)

	Tennessee Gas Pipeline			Columbia Gulf	Texas Eastern	Midwestern	
	Z0-100	Z1-500	Z1-800	Rayne	ELA	Chicago	TOTAL
July 2011	[redacted]						
August							
September							
October							
November							
December							
January 2012							
February							
March							
April							
May							
June							
Subtotal							
July 2012							
August							
September							
October							
November							
December							
January 2013							
February							
March							
April							
May							
June							
Subtotal							
July 2013							
August							
September							
October							
November							
December							
January 2014							
February							
March							
April							
May							
June							
Subtotal							
TOTAL							
PERCENT							

Table 11.
PIEDMONT NATURAL GAS COMPANY
Citygate Purchase Quantities and Prices

Month/Year	Columbia Gulf	Texas Eastern[1]	MGT East via Gulf	MGT East via ETNG to Boat Dock	MGT East via Gulf to Walnut Grove	MGT West via TGP	TOTAL
	CITYGATE PURCHASE QUANTITIES (Dth)						
January 2012	[redacted]						
June							
Subtotal							
July 2012							
August							
October							
November							
December							
January 2013							
February							
March							
April							
May							
Subtotal							
August 2013							
September							
October							
November							
December							
January 2014							
February							
March							
April							
Subtotal							
TOTAL							
PERCENT							
	CITYGATE PURCHASE PRICES ($/Dth)						
January 2012	[redacted]						
June							
August							
October							
November							
December							
January 2013							
February							
March							
April							
May							
August							
September							
October							
November							
December							
January 2014							
February							
March							
April							

Note: [1] Includes out-of-period adjustments.

3.1.3 Results and Conclusions

Table 12 presents a summary of Piedmont's gas commodity procurement incentive mechanism purchases and gains and losses by month and type of purchase (i.e., monthly, daily, citygate). [redacted].

Weighting the Benchmark for Monthly Purchases by Capacity Entitlements. Under Piedmont's Plan, savings are achieved if actual gas costs are less than benchmark costs. A study evaluating gas procurement mechanisms conducted by the National Regulatory Research Institute (NRRI) found that savings are only truly achieved if the benchmark formula accurately estimates the costs that would have been without the incentive mechanism under traditional regulation.[4] The NRRI study further found that this is often not the case and that benchmarks are often easy to beat. Piedmont's Performance Incentive Plan was reviewed as part of the NRRI's study. Exeter's review of Piedmont's Plan concludes that the benchmark for monthly purchases included in the MBIP is too easy to beat and not reflective of the costs that would have been experienced under traditional regulation. Although a relatively extreme example, as previously shown in Table 7, for March 2014, the benchmark for monthly purchases included in the MBIP indicated that a savings of [redacted] was achieved by simply avoiding the purchase of [redacted].

The benchmark for monthly purchases included in the MBIP under the Plan provides an incentive to purchase gas at receipt point locations with the lowest total delivered variable cost. While such an incentive is desirable, it is Exeter's concern that the benchmark for monthly purchases provides rewards that greatly exceed any improvement in Piedmont's commodity cost procurement performance, and the benchmark does not reflect costs that would be experienced under traditional regulation. Piedmont is simply utilizing price intelligence that all market participants have available to decide at which receipt point locations to purchase its gas supplies. As discussed in Section 3.2 of the Report, Piedmont pays supplier reservation fees which guarantees that Piedmont is able to pay average market prices for gas with no risk. It is Exeter's conclusion that the benchmark for monthly purchases provides rewards for performance that are

[4] *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, National Regulatory Research Institute, November 2006.

not superior to those of other market participants. Gas utilities operating under traditional regulation routinely maximize the purchase of gas at receipt point locations with the lowest total

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Table 12.
PIEDMONT NATURAL GAS COMPANY
Summary of Review Period Purchases and Commodity Procurement Gains/(Losses)

	Purchases by Type (Dth)				Gains/(Losses) by Type of Purchase			
Month/Year	First of Month	Daily	Citygate	TOTAL	First of Month	Daily	Citygate	TOTAL
July 2011	[redacted]							
August								
September								
October								
November								
December								
January 2012								
February								
March								
April								
May								
June								
Subtotal								
July 2012								
August								
September								
October								
November								
December								
January 2013								
February								
March								
April								
May								
June								
Subtotal								
July 2013								
August								
September								
October								
November								
December								
January 2014								
February								
March								
April								
May								
June								
Subtotal								
TOTAL								
PERCENT								

delivered variable cost. Atmos and Chattanooga, two other Tennessee gas utilities that operate under gas cost incentive mechanisms, also maximize the purchase of gas at receipt point locations with the lowest total delivered cost. Neither Atmos nor Chattanooga realize rewards for maximizing the purchase of the lowest-cost monthly supplies under their incentive mechanisms. The incentive mechanisms of Atmos and Chattanooga are further discussed in Section 7 of the Report.

In its comments on previous Exeter Plan reports, Piedmont has indicated that the intended goal of the Plan was not to provide rewards only when the Company out-performed other market participants. Piedmont stated that the goal of the Plan was to align the interests of the Company 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 benchmark for monthly purchases included in the MBIP results in gas cost "savings" that would have been realized without the existence of the Plan. Exeter would note, however, that beginning with the winter of 2014-2015, as a result of the reduction to the amount of Midwestern capacity available to meet design day demands discussed in Section 2.4, the savings achieved under the Plan associated with monthly purchases can be expected to significantly decline.

Exclusion of Certain Capacity Entitlements from the Weightings Used to Develop the Benchmark for Monthly Purchases. The tariff language describing the Plan indicates that the benchmark for monthly purchases included in the MBIP be determined by weighting the monthly index price for each geographic area (pipeline location) by the percentage share of capacity entitlements for each pipeline location to the Company's total capacity entitlements. In its review period monthly purchase benchmark calculations, the Company excluded its Columbia Gulf backhaul capacity even though that capacity was identified as being available to meet design day demands. Piedmont indicated that the Columbia Gulf backhaul capacity was excluded from its monthly purchase benchmark calculations because the Company did not contract for the delivery of gas under its backhaul capacity, and if it had, it would have been necessary to incur significant increases in the delivered cost of gas. Exeter's analysis indicates that, if considered in isolation, excluding the Columbia Gulf backhaul capacity from the monthly purchase benchmark calculations had the effect of slightly increasing the MBIP and increasing the Company's rewards under the Plan. However, to contract for the delivery of gas under its Columbia Gulf backhaul capacity Piedmont would have incurred supplier reservation fees and the Plan provides for 100 percent recovery of these fees. Exeter's analysis also indicates that based on supplier reservation fees paid by other gas utilities for Columbia Gulf backhaul supplies, the supplier reservation fees associated with the backhaul supplies would have exceeded any customer benefits realized by the inclusion of Columbia Gulf backhaul capacity in Piedmont's benchmark for monthly purchases.

As previously indicated in Section 2.1.4 of the Report, Piedmont reduced the amount of Midwestern capacity included in its monthly benchmark calculations during the summer [redacted] Piedmont also indicated that it believed including the full amount of the capacity would artificially inflate the MBIP. The effect of reducing Midwestern capacity entitlements in the monthly purchase benchmark calculations was to reduce the MBIP and to slightly reduce the Company's rewards under the Plan. Although the Plan provides for the exclusion of released capacity from the calculation of the benchmark for monthly purchases, the Plan does not specifically provide for Piedmont's review period Columbia Gulf and Midwestern capacity entitlement exclusions. To avoid the potential for controversy in the future, Exeter recommends that the Plan tariff language be further clarified to specify when capacity should be included or excluded from the monthly purchase benchmark calculation if the Plan continues under its present structure.

Exeter's review also noted that the particular paths for the delivery of Midwestern supplies included in the monthly purchase benchmark calculations were generally based on operational requirements and least-cost procurement. Exeter's review found no concerns with the particular delivery paths included in Piedmont's monthly purchase benchmark calculations, and that the particular paths selected had little impact on Plan results.

Citygate Purchases. As indicated previously, the Plan does not appear to specifically address the benchmarking procedures applicable for citygate purchases. Therefore, it is unclear whether the procedures used by Piedmont to establish benchmark costs for citygate purchases are consistent with the requirements of the Plan. As previously shown on Table 12, [redacted]. Table 13 identifies Piedmont's citygate purchases by the interstate pipeline delivery path assigned to the purchases by Piedmont during the winter of 2013-2014, as well as the index price used for benchmarking purposes and the associated [redacted]. As shown, the [redacted].

[redacted]

Table 13.
PIEDMONT NATURAL GAS COMPANY
Citygate Purchases
(2013-2014 Winter Season)

		[redacted]		
Assigned Delivery Path	**Total Volume (Dth)**	**Total**	**Per Unit ($/Dth)**	**Benchmark**
MGT East via ETNG to Boat Dock	[redacted]			
MGT East via Gulf to Walnut Grove	[redacted]			
MGT West via TGP	[redacted]			
Columbia Gulf IT	[redacted]			
TOTAL	[redacted]			

In industry publications such as *Inside FERC* and *Natural Gas Intelligence*, Chicago citygate index prices reflect volume weighted prices for deliveries at the citygates of several Chicago metropolitan area gas utilities: Nicor Gas, Peoples Gas Light & Coke (Peoples), North Shore Gas, and Northern Indiana Public Service Company (NIPSCO). The Chicago area is served by a number of interstate pipelines, including ANR Pipeline and Natural Gas Pipeline Company of America (NGPL). The first three months of 2014 were marked by historically cold weather and record high natural gas and electricity demand, which resulted in high natural gas prices.[6] Four major cold events occurred during January and February 2014 which had a significant impact on natural gas markets, followed by a less extensive event in early March 2014.[7] The first three major cold events occurred on January 6-7, January 22, and January 27, and primarily affected natural gas markets in the upper Midwest, the Northeast, and the Southeast.[8] On January 27, 2014, cold weather in the upper Midwest coincided with an explosion on TransCanada's system in Manitoba which disrupted natural gas supply deliveries to the Midwest. On January 28, 2014, Chicago citygate index prices reached $42.20 per Dth. The fourth major event occurred on February 6 and affected much of the Midwest.[9] There was also a cold weather event during the first week in March, primarily affecting the Midwest markets.[10]

During the winter of 2013-2014, Piedmont contracted with [redacted] for firm gas supplies sufficient to fill the Company's 100,000 Dth per day of Midwestern capacity at a [redacted]. At the time, this contracting

[6] http://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.
[7] Ibid.
[8] Ibid.
[9] Ibid.
[10] Ibid.

practice was consistent with standard industry practice. While natural gas prices generally increased throughout much of the United States in response to the extreme cold in early 2014, the price increases were not as pronounced as those observed in certain markets such as the Chicago area. For example, while Chicago citygate prices as high as \$58.00 per Dth were reported during the week of January 28 – February 3, 2014, the highest prices reported for TGP Zone 0 – 100 Leg and Columbia Gulf Mainline did not exceed \$8.00 per Dth.[11]

In response to the high Chicago citygate index prices, Piedmont sought alternatives to firm supplies from [redacted] at locations other than the Chicago citygate, and was successful in replacing those supplies with lower-cost citygate purchases. Exeter's review indicates that Piedmont would have purchased approximately [redacted] Dth of Chicago citygate gas supplies for the period January – March 2014 to meet its sales customers' requirements under the extreme weather conditions, but instead only purchased [redacted] Dth of Chicago citygate [redacted] during this period.

Piedmont benchmarked the citygate purchases made to displace its Chicago citygate purchases based on Chicago citygate index prices. This resulted in significant savings under the Plan. For example, on [redacted] Piedmont was able to generate savings of nearly [redacted]. Piedmont indicated that it benchmarked its replacement purchases against Chicago citygate index prices because it was Chicago citygate purchases that were being replaced.

The benchmarking of citygate purchases is not specifically addressed in the Plan. It can be argued that tariff language describing the Plan indicates that these citygate upstream purchases should have been benchmarked based on index prices applicable for the receipt point location where the gas was purchased by the supplier. The receipt point location of these replacement supplies would be unknown to Piedmont unless the supplier was willing to provide Piedmont with that information, which is unlikely since it would have revealed commercially sensitive information, and the supplier would have no obligation to provide the information. Alternatively, it can be argued that these supplies should have been benchmarked against an index location in close proximity to Piedmont's system, adjusted for applicable variable charges. Finally, it can be argued that the citygate replacement supplies were appropriately benchmarked by Piedmont. [redacted]

[11] *Natural Gas Week*, February 3, 2014.

[redacted]

Exeter recommends that the Settling Parties consider modifying the tariff language of the Plan to clearly establish the benchmarking procedures for citygate replacement purchases that may be made in the future. Exeter recognizes that such purchases will have less of an impact on the determination of Plan savings in the future, as Piedmont has determined that the Midwestern capacity available to meet design day demands should be reduced from 100,000 Dth to 25,000 Dth per day.

IT Tariff Language. The modifications to the Plan that were made effective March 1, 2012 provide for the inclusion of IT delivered supplies in calculating the monthly purchase benchmark included in the MBIP. It is Exeter's understanding that this was done to include the variable costs associated with delivering Midwestern sourced gas to Piedmont's system by Columbia Gulf to Walnut Grove and by ETNG to Boat Dock under interruptible arrangements. Exeter is in concurrence with the inclusion of these IT variable costs in the MBIP calculations. However, as written, in Exeter's view, the Plan tariff language suggests that IT arrangements could be utilized in developing the monthly capacity factors weightings. Exeter does not believe that this would be appropriate as it may permit the inclusion of high-cost IT supplies in the capacity weightings, which the Company has no intention of purchasing. While Piedmont did not include high-cost IT supplies in the monthly weightings during the review period and it appears the Company has no intention of doing so, Exeter suggests that the Plan tariff language be modified to clarify the initial intent of including IT supplies in the monthly purchase benchmark.

[redacted] *IT Purchases*. One of the citygate purchase arrangements entered into by Piedmont during the review period provided for the delivery of supplies by [redacted]. Under this arrangement, Piedmont paid a [redacted]. These [redacted] citygate purchases had a lower delivered cost than if gas supplies were purchased and delivered under Piedmont's [redacted] firm transportation capacity arrangements. As a result, Piedmont used the citygate purchases to displace significant quantities of [redacted] deliveries. Under the Plan, however, the benchmark for the [redacted] citygate purchases was much higher than the benchmark for [redacted] deliveries. This is because although the same [redacted] was used for both citygate deliveries and [redacted] deliveries, the variable charges associated with the citygate purchases were based on [redacted] rather than the otherwise applicable lower [redacted] variable charges. After accounting for Piedmont's share of savings from these citygate purchases, customers were actually charged more (approximately [redacted]) for the citygate supply purchases than if the supplies were transported under Piedmont's [redacted] arrangements. Thus, customers were charged more when lower-cost gas supplies were purchased than when higher-cost gas supplies were purchased. While the additional costs charged to ratepayers were relatively small, the current structure of the Plan does not appear to provide appropriate incentives for IT delivered citygate purchases.

3.2 Supplier Reservation Fees Component

3.2.1 Background and Description

The Plan allows Piedmont to recover 100 percent of its gas supplier reservation fees with no profit or loss potential. Piedmont entered into a number of gas supply contracts with supplier reservation fees during the review period. These fees generally ranged from [redacted] to [redacted] per Dth, per day, of the contracted MDQ. Review period supplier reservation fees ranged from [redacted] to [redacted] per year, and totaled [redacted] for the review period. Piedmont's gas supply contracts generally provided for [redacted].

3.2.2 Results and Conclusions

Gas supply contracts can be arranged to provide for a discount on commodity index prices in exchange for higher demand charge supplier reservation fees. The Plan requires modifications to the applicable index price to reflect such discounts. Gas supply contracts can also be arranged that provide for the ability to purchase gas at first-of-the-month index prices after the first of the month, when daily market gas prices are higher (first-of-the-month call option) in exchange for higher demand charge fees. With 100 percent recovery of supplier reservation fees, monthly call option contracts could improperly reward Piedmont. All of the Company's contracts with supplier reservation fees during the review period included [redacted]. Therefore, Exeter found no concerns with Piedmont's administration of supplier reservation fees under the commodity procurement cost component of the Plan during the review period. Exeter does note, however, that guaranteed recovery of supplier reservation fees provides Piedmont with little incentive to minimize these fees.

3.3 Capacity Management Component

3.3.1 Background and Description

Piedmont realized revenues under the capacity management component of the Plan through asset management agreements and off-system sales during the review period. Table 14 summarizes the capacity management revenues realized by Piedmont during the review period.

Table 14.
PIEDMONT NATURAL GAS COMPANY
Summary of Review Period Capacity Management Revenues

	Asset Management	Off-System Sales Volumes (Dth)	Off-System Sales Margin	Revenues Total	Revenues Company 25%	Revenues Ratepayers 75%
July 2011	[redacted]					
August						
September						
October						
November						
December						
January 2012						
February						
March						
April						
May						
June						
Subtotal						
July 2012						
August						
September						
October						
November						
December						
January 2013						
February						
March						
April						
May						
June						
Subtotal						
July 2013						
August						
September						
October						
November						
December						
January 2014						
February						
March						
April						
May						
June						
Subtotal						
TOTAL						

Piedmont is entitled to retain 25 percent of capacity management revenues, up to a cap of $1.6 million, including gains under the commodity procurement cost component of the Plan. The 25 percent Company sharing for AMA revenues is at the high end of the sharing procedures adopted in other jurisdictions, and the 25 percent Company sharing for off-system sales margin is consistent with Exeter's experience in other jurisdictions.

Piedmont's review period AMAs were previously identified in Table 4 in Section 2.4 of the Report. As shown in there, the annual AMA fee received for the period [redacted]. However, under the AMA awarded by Piedmont for the period [redacted].

Capacity release revenues are also subject to sharing under the capacity management component of the Plan. However, Piedmont released all of its interstate pipeline capacity to the AMA Asset Manager and, therefore, Piedmont did not engage in capacity release activities during the review period.[12] The release of all of its capacity to the Asset Manager also limited Piedmont's ability to engage in off-system sales activities during the review period. [redacted]. A significant percentage of Piedmont's off-system sales were sales to the Asset Manager in the production area that were subsequently repurchased by Piedmont at the citygate at the same cost the as the gas sold to the Asset Manager. These off-system sales were made to comply with the FERC's Shipper Must Have Title Policy, and generated no margin.

3.3.2 Results and Conclusions

Exeter's most recent prior triennial review of Piedmont's Plan identified a general concern with Piedmont's off-system sales activities in that the supplies being sold off-system were frequently later being replaced with higher-cost supplies, adversely impacting the gas costs of sales customers. This concern has also surfaced during the current review period.

Piedmont released all of its review period interstate pipeline capacity under its AMAs and, therefore, the Company was unable to use its interstate pipeline capacity to engage in off-system sales activity. Piedmont's review period off-system sales profit opportunities were

[12] The release of all of a gas utility's interstate pipeline capacity under an AMA is a standard industry practice.

largely limited to Gulf Coast production area sales when the daily price of gas was below the monthly price for flowing gas supplies. When Piedmont engages in these off-system sales, the Company frequently purchased supplies at the same location several days later at higher prices. Had Piedmont not sold monthly supplies off-system and instead injected those supplies into storage, it could have potentially reduced the following month's higher-priced monthly purchases. Examples of Piedmont selling lower-cost monthly supplies off-system and purchasing higher-cost monthly supplies the following month are as follows:

- The sale of [redacted] Dth of [redacted] monthly supplies with a cost of [redacted] per Dth during the period July 21-27, 2012, and the purchase of [redacted] monthly gas at a price of [redacted] per Dth in August 2012; and
- The sale of [redacted] Dth of [redacted] monthly supplies with a cost of [redacted] per Dth during the period December 19-22, 2013, and the purchase of [redacted] monthly gas at a price of [redacted] per Dth in January 2014.

In Exeter's most recent prior review of Piedmont's Plan, we noted a concern that Piedmont was selling its lowest-cost supplies off-system rather than its highest-cost supplies. This maximized the benefits for Piedmont but not necessarily its sales customers. While Exeter did not review the circumstances regarding every one of the hundreds of off-system sales made by Piedmont during the review period, the sale of lowest-cost supplies off-system did not surface as an evident concern.

In conclusion, Piedmont's off-system sales activities contributed relatively little to the generating of capacity management revenues, totaling [redacted] over the three-year review period. Piedmont's off-system transactions frequently had an adverse impact on the gas costs of sales customers while generating a reward for Piedmont under the Plan. Except for potentially operational reasons and those off-system sales made to comply with the FERC's Shipper Must Have Title Policy, Exeter concludes that it would be in the best interest of ratepayers if Piedmont did not engage in off-system sales when all of the Company's capacity is assigned under an AMA.

4.0 STORAGE ACTIVITY

The Statement of Work for this investigation, as identified in the RFP, requires the review of Piedmont's gas procurement, capacity management, and off-system sales activities and transactions. These transactions and activities were reviewed in detail in Section 3 of this Report. Also required for review are Piedmont's storage activities, which are described in this section.

4.1 Storage Arrangements and Activity

As discussed in greater detail in Section 2 of this Report, Piedmont purchased unbundled storage service from TGP under Rate Schedules FS-MA and FS-PA, and from Columbia Gas under Rate Schedule FSS. Piedmont also owns and operates an LNG storage facility. The Company's storage arrangements during the review period are summarized in Table 15.

Table 15.
PIEDMONT NATURAL GAS COMPANY
Summary of Review Period Storage Service Arrangements

Service	Rate Schedule	Maximum Withdrawal Quantity (Dth)	
		Daily	Seasonal
Tennessee Gas Pipeline	FS-MA	49,828	2,901,943
Tennessee Gas Pipeline	FS-PA	6,072	672,091
Columbia Gas Transmission	FSS	10,000	611,870
Piedmont LNG		[redacted]	
TOTAL			

Table 16 identifies the monthly storage activity (injections/withdrawals) and the inventory balances under each of Piedmont's storage arrangements at the conclusion of each month of the review period. Also shown are storage inventory balances as a percent of the Company's maximum seasonal contract quantity. The storage activity presented in Table 16 reflects Piedmont's virtual dispatch use of storage, and not the actual physical use of storage by its Asset Managers.

Table 16.
PIEDMONT NATURAL GAS COMPANY
Summary of Review Period Storage Activity
(Dth)

	Tennessee Gas Pipeline (FS-MA)			Tennessee Gas Pipeline (FS-PA)			Columbia Gas Transmission (FSS)			Piedmont (LNG)		
	(Injection)/ Withdrawal Activity	Ending Inventory	% Capacity 2,901,943	(Injection)/ Withdrawal Activity	Ending Inventory	% Capacity 672,091	(Injection)/ Withdrawal Activity	Ending Inventory	% Capacity 611,870	(Injection)/ Withdrawal Activity	Ending Inventory	% Capacity 920,000
July 2011	[redacted]											
August												
September												
October												
November												
December												
January 2012												
February												
March												
April												
May												
June												
July												
August												
September												
October												
November												
December												
January 2013												
February												
March												
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May												
June												
July												
August												
September												
October												
November												
December												
January 2014												
February												
March												
April												
May												
June												

4.2 Storage Planning Guidelines

Piedmont has established general storage planning guidelines that identify the inventory balances the Company plans to maintain. Piedmont targets to fill TGP FS-MA and FS-PA storage to [redacted] of capacity prior to the start of the storage withdrawal season (November 1), and to fill Columbia Gas storage and the Company's LNG storage to [redacted] of capacity prior to the start of the storage withdrawal season. [redacted]. Piedmont plans to reduce the storage inventory balances under each of its interstate pipeline storage services to no less than [redacted] by the conclusion of the storage withdrawal season (March 31). Columbia Gas' FERC tariff for FSS includes storage inventory cycling requirements that Piedmont is required to follow. No such cycling requirements exist under TGP's tariff for FS-MA or FS-PA. LNG storage is used when needed to meet customer demands and/or meet the operational requirements of the facility to cycle gas (i.e. if the BTU value is high the gas may need to be cycled). Piedmont's actual and planned interstate pipeline inventory balances during the review period are summarized in Table 17. As shown, actual beginning of storage season balances were generally consistent with planned balances. However, end of storage season inventory balances, and specifically TGP inventory balances, significantly exceeded planned balances.

Table 17.
PIEDMONT NATURAL GAS COMPANY
Review Period Planned and Actual Storage Inventory

	March 31		November 1	
Year	**Planned**	**Actual**	**Planned**	**Actual**
Tennessee Gas Pipeline (FS-MA/FS-PA)				
2011	[redacted]			
2012				
2013				
2014				
Columbia Gas (FSS)				
2011	[redacted]			
2012				
2013				
2014				

Piedmont's TGP and Columbia Gas storage inventory balances at the conclusion of the 2011-2012 winter season were at [redacted] and [redacted] of capacity, respectively, well in excess of the [redacted] planned balances. These storage balances exceeded Piedmont's planning criteria due to: (1) weather which was 23 percent warmer than normal; and (2) [redacted].

At the conclusion of the winter of 2012-2013, TGP storage inventory balances were at [redacted] of capacity, while the Columbia Gas inventory balance was at [redacted] of capacity and consistent with the Company's [redacted] planning criteria. Weather during the winter of 2012-2013 was 5 percent warmer than normal, which contributed to TGP storage inventory balances exceeding planned balances [redacted].

Although weather during the winter of 2013-2014 was 12 percent colder than normal, Piedmont's TGP storage inventory was at [redacted] of capacity, and Columbia Gas storage inventory was at [redacted] of capacity, both of which exceeded the [redacted] planning guideline. Inventory balances exceeded the planning guidelines due to a significant change in the Piedmont distribution system. In December 2013, a 24-inch transmission main was installed on the east side of Piedmont's system which is served primarily by Columbia Gulf. This change increased demand on the east side of Piedmont's system served by Columbia Gas and reduced demand on the west side of the system served by TGP. A period of time was required by Piedmont to gather operating data and adjust its daily load forecasts on TGP and Columbia Gulf to incorporate the impact of the new main. Due to the uncertainty of the impact of the changes caused by the new main, Piedmont took a conservative approach to TGP storage utilization. Piedmont's load forecasts for TGP demand initially overestimated demands on very cold days, frequently resulting in storage injection when withdrawals were planned.

In conclusion, Exeter's review finds that Piedmont's storage inventory planning criteria were generally reasonable, and were consistent with the criteria used by other gas distribution companies. Piedmont generally adhered to those criteria unless market conditions or operational requirements indicated that deviations were appropriate. Therefore, Piedmont's review period storage activity appears reasonable.

5.0 EVALUATION OF CAPACITY PORTFOLIO AND IDENTIFICATION OF VARIABLE CHARGES

5.1 Design Day Forecast and Criteria

Piedmont secures sufficient capacity resources to meet the forecasted design day requirements of its sales customers and those transportation customers that select standby service. During the review period, Piedmont's design peak day forecast calculation involved several steps. First, actual throughput and heating degree days (HDDs) experienced on the most recent day that approached Piedmont's design day temperature criteria were determined. The date used by Piedmont during the review period was January 23, 2003, when 57.9 HDDs were recorded. Piedmont's design day temperature criterion during the review period was 67 HDDs (-2°F). Next, interruptible usage was removed from total throughput to determine firm requirements. Firm requirements were then increased by usage per HDD factors developed from a regression analysis using data from 1995 through 2008 to estimate what firm requirements would have been under design day conditions. This total was 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 was being prepared. Finally, usage of firm transportation customers not selecting standby service was removed and a 5 percent reserve margin was added to determine Piedmont's capacity requirements.

After experiencing the Polar Vortex during the winter of 2013-2014, Piedmont reviewed its design day forecasting methodology and determined that changes were necessary. Piedmont's design day forecast is now based on an analysis of daily winter sendout for the three-year period April 2011 through March 2014, utilizing those days with greater than 10 HDDs. Through this analysis, Piedmont determined baseload usage and usage per HDD factors and utilized these usage factors to determine forecasted design day demands. Included in the Company's forecast of design day demands is a 5 percent reserve margin. Customer growth is also reflected in the Company's forecasts.

In addition to changing its forecasting methodology in response to the Polar Vortex of 2013-2014, Piedmont also revised its design day temperature criteria from 67 to 70 HDDs. This reflects the coldest average daily temperature observed in the Company's service territory over the last 40 years. The Company selected this criterion because it concluded that it was necessary to either factor wind speed into its design day forecast or that a historical low temperature experienced over at least 40 years should be utilized. The Company subsequently determined that utilizing the coldest daily temperature over the last 40 years would be sufficient to provide reliable service to its firm customers.

Exeter's prior triennial review of Piedmont's Plan found the 67 HDD design day temperature criteria, coupled with maintaining a 5 percent reserve margin, to be conservative but not unreasonable. Piedmont recently adopted 70 HDD as its design day planning criteria to reflect the coldest day in 40 years rather than specifically account for wind speed in its design day forecast. In response to Exeter's Draft Report, Piedmont indicated that prior day temperatures had a significant impact on customer usage during peak (colder) periods. Piedmont does not currently account for prior day temperatures in its design day forecast. Based on Piedmont's Draft Report comments, Exeter requested, and Piedmont provided, additional weather data and Exeter performed additional analysis. Based on this additional analysis, Exeter finds Piedmont's 70 HDD design day planning criteria to be reasonable. Exeter recommends that Piedmont explicitly explore including wind speed and prior day temperature variables in its sendout forecasting model.

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

5.2 Actual Peak Day and Design Day Forecasting Accuracy

Table 18 summarizes the actual peak day sendout of firm customers (sales and transportation) during each winter season of the review period and projected firm design day demands.[13] Both sendout numbers include the demands of firm transportation customers that have not elected standby service. The projected design day demands of firm transportation customers not electing standby service were 16,002 Dth for the winter of 2011-2012; 14,647 Dth for the winter of 2012-2013; and 11,661 Dth for the winter of 2013-2014. Also shown in Table 18 are actual heating degree days. Because each actual peak day was considerably warmer than Piedmont's review period 67 HDD design day, the sendout of firm customers was significantly less than the forecasted sendout of firm customers on the applicable design day.

[13] The actual peak day of firm customers did not always occur on the same day that the overall system peak day occurred due to interruptible transportation customer volumes.

Table 18. PIEDMONT NATURAL GAS COMPANY Summary of Actual Firm Peak Day Sendout			
		Sendout (Dth)	
Date	HDD	Actual	Design
February 11, 2012	41	[redacted]	371,151
January 22, 2013	38		372,118
January 28, 2014	53		374,229

A comparison of actual peak day firm requirements and forecasted requirements under actual weather conditions using Piedmont's design day forecasting model can provide an indication of the predictive capability of the Company's design day forecasting model. However, the design day forecasts presented above in Table 18 are based on the method used by Piedmont prior to experiencing the Polar Vortex in the winter of 2013-2014 and is no longer relied upon by the Company. Assessing the predictive capability of an approach no longer used is of little value. To assess the predictive capability of the approach now used by the Company, Exeter compared actual firm sendout on January 28, 2014 with the forecasted firm sendout under actual weather conditions of 53 HDDs on the same date using the Company's new approach. As shown on Table 18, actual sendout on January 28, 2014 was [redacted] Dth, and the Company's new forecasting approach projected sendout of 286,785 at 53 HDDs, a difference of [redacted] percent. This suggests that Piedmont's new design day forecasting approach is reasonable.

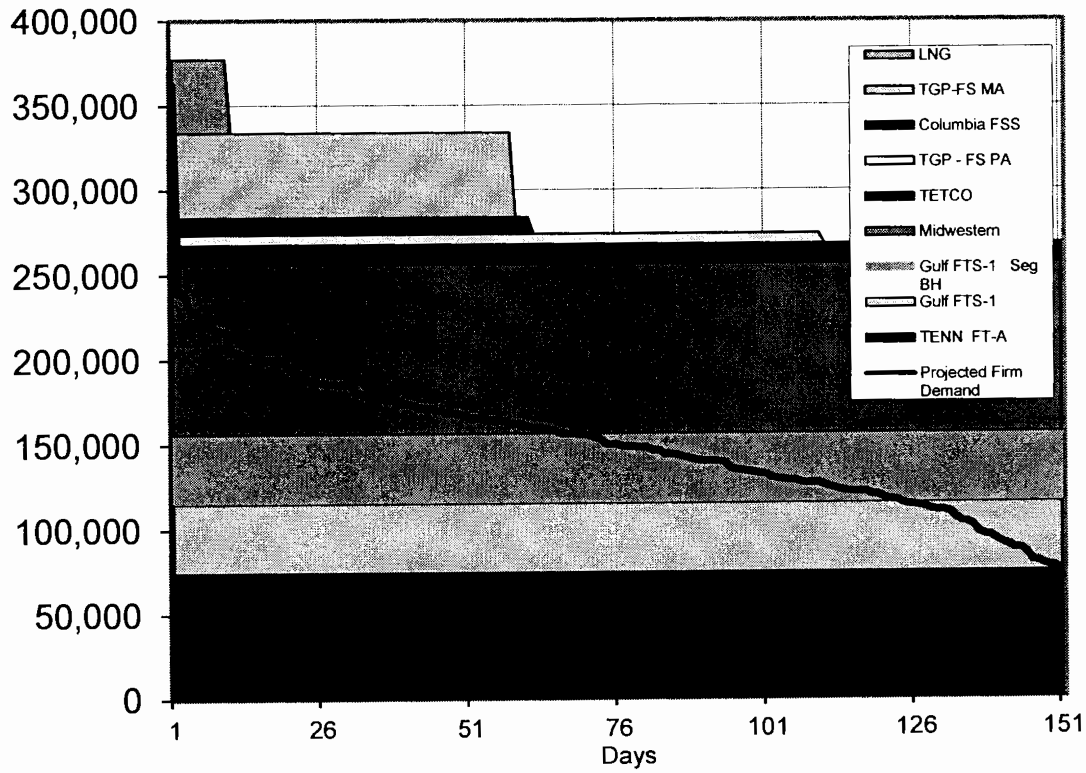
5.3 Balance of Capacity Resources and Design Day Requirements

As initially shown on Table 2, the capacity resources available to meet Piedmont's design peak day requirements for the 2013-2014 winter season totaled 377,277 Dth. Estimated design day firm sales requirements, including the requirements of firm transportation customers that select standby service and excluding the 5 percent reserve margin, totaled 362,568 Dth, indicating that Piedmont maintained a capacity surplus of 14,709 Dth, or a 4.1 percent reserve margin at the conclusion of the review period. This reserve margin was expected to decrease by approximately 3,000 Dth per year due to system load growth. As explained Section 5.1 of this Report, since the conclusion of the review period, Piedmont has increased its design day criteria from 67 to 70 HDDs, which had the effect of increasing design day requirements by approximately 15,000 Dth.

5.4 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 2013-2014 winter season totaled 45.4 billion cubic feet (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 22.9 Bcf. Thus, from a planning perspective, Piedmont's winter season capacity resources exceed requirements by 22.5 Bcf, or approximately 50 percent. Piedmont attempts to obtain value for capacity that is not currently required to meet customer requirements by releasing the capacity under AMAs. Piedmont's winter period load duration curve for the winter of 2013-2014 is presented in Figure 2. This demand curve illustrates the extent to which Piedmont maintained capacity in excess of its customers' requirements at the conclusion of the review period.

Figure 2.
2013-2014 Load Duration Curve
Design Winter



5.5 Annual Capacity Resources and Requirements

The estimated requirements of Piedmont's sales customers during a year in which a design winter season is experienced are approximately 28.7 Bcf. As shown previously on Table 2, the capacity resources available to meet Piedmont's annual requirements totaled 87.5 Bcf at the conclusion of the review period. Approximately 4.0 Bcf of this capacity is used to fill storage during the summer period. Based on annual requirements of 28.7 Bcf and 4.0 Bcf of summer storage injections, Piedmont maintained an annual deliverability surplus of approximately 54.8 Bcf, or approximately 60 percent. Piedmont's excess annual capacity balance is further discussed in Section 5.6.

5.6 Capacity Portfolio Modifications

The RFP Statement of Work for Exeter's 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 Statement 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 in Table 19. Actual review period utilization of this capacity for the third year of the review period is presented in Table 20. Utilization for this year is analyzed because the winter of 2013-2014 was 12 percent colder than normal, comparable to the 15 percent colder-than-normal winter that Piedmont utilizes for planning purposes. As shown in Table 20, the Company's winter season [redacted] The Company's other firm transportation arrangements were utilized [redacted]. Also shown in Table 20, the year-round TGP FT-A capacity was utilized at a load factor of [redacted] and Columbia Gulf capacity was utilized at a load factor of [redacted]. The Company's MGT capacity was [redacted] during the review period. The MGT capacity [redacted] This indicated that during the review period, the Company maintained excess year-round firm transportation capacity, and that the Company could have reduced its demand charges by decreasing its year-round capacity and placing greater reliance on winter season capacity or delivered supply services.

Table 19.
PIEDMONT NATURAL GAS COMPANY
Summary of Interstate Pipeline Firm Transportation Charges

Pipeline/(Contract Number)	Demand Quantity (Dth) Winter	Summer	Annual	Monthly Demand Charge ($/Dth)	Annual Demand Cost
Columbia Gulf					
FTS-1 (43462)	10,000	5,000	3,479,228	$2.7375	$313,208
FTS-1 (14252)	31,000	11,755	7,196,570	$4.2917	$1,018,356
FTS-1 Backhaul	41,000	20,957	10,675,798	--	--
Midwestern Gas Transmission					
FT-A (FA0342)	100,000	100,000	36,500,000	$1.8240	$2,188,800
FT-B (FB0006)	100,000	100,000	36,500,000	$2.6310	$3,157,200
Tennessee Gas Pipeline					
FT-A (237)	74,100	74,100	27,046,500	$5.3832	$4,786,705
FT-BH (46715)	81,900	81,900	--	$0.6720	$666,442
Texas Eastern					
FT-1 (910473)	10,000	0	1,510,000	$12.4708	$623,540
SCT (800059)	1,677	1,677	204,035	(1)	(1)

Note:
(1) Piedmont's current utilization of the Texas Eastern SCT contract is less than 20 percent. When this occurs, there are no demand charges associated with SCT service.

Table 20.
PIEDMONT NATURAL GAS COMPANY
Summary of Firm Transportation Utilization
(July 2013 – June 2014 Plan Year)

Pipeline/Rate Schedule	Annual Quantity (Dth) Contract	Actual	Load Factor
Columbia Gulf			
FTS-1	10,675,798	[redacted]	
Midwestern Gas Transmission			
FT-A / FT-B	36,500,000		
Tennessee Gas Pipeline			
FT-A	27,046,500		
Texas Eastern			
FT-1	1,510,000		
TOTAL	**75,732,298**		
TOTAL – Excluding MGT	**39,232,298**		

Notes:
[redacted]

As previously explained in greater detail in Section 2.4 of this Report, significant changes to Piedmont's capacity portfolio occurred after the conclusion of the review period. These changes included:

- A reduction to the Midwestern capacity determined to be available to meet design day demands from 100,000 Dth to 25,000 Dth per day;
- A reduction in TGP capacity from 74,100 Dth to 37,000 Dth per day;
- The purchase of a [redacted] and
- The restoration of LNG deliverability to [redacted] Dth per day.

Rather than assess the potential for Piedmont to reduce its demand charges by decreasing the year-round capacity included in a winter of 2013-2014 capacity portfolio that has since changed significantly, Exeter has assessed this potential based on the capacity portfolio that existed for the winter of 2014-2015.

Table 21 summarizes Piedmont's design day, winter season, and annual capacity entitlements based on the Company's winter of 2014-2015 capacity portfolio.

Table 21.
PIEDMONT NATURAL GAS COMPANY
Summary of Design Day Capacity Resources
(2014-2015 Winter Season)
(Dth)

Pipeline - Service	MDQ Winter	MDQ Summer	Available Quantity Winter Season	Available Quantity Annual	Contract Expiration
Columbia Gas					
Storage Service (FSS/SST)	10,000	5,000	611,870	0	3/31/2024
Columbia Gulf					
Firm Transportation (FTS-1)	10,000	9,202	1,510,000	3,479,228	10/31/2022
Firm Transportation (FTS-1)	31,000	11,755	4,681,000	7,196,570	10/31/2018
Midwestern Gas Transmission					
Firm Transportation (FT-A)/(FT-B)	25,000	25,000	3,775,000	9,125,000	01/06/2023
Tennessee Gas Pipeline					
Firm Transportation (FT-A)	37,000	37,000	5,587,000	13,505,500	10/31/2019
Storage Service (FS-MA/FT-BH)	49,828	0	2,901,943	0	10/31/2019
Storage Service (FS-PA/FT-BH)	6,072	0	672,091	0	10/31/2019
Texas Eastern Transmission					
Firm Transportation (FT-1)	10,000	0	1,510,000	1,510,000	03/31/2019
Firm Transportation (SCT)	1,677	1,677	84,409	204,035	10/31/2015
Piedmont LNG	[redacted]				
Citygate Delivered Supply Service					
Total Citygate Capacity Resources					

Piedmont's projected design day for the winter of 2014-2015, exclusive of its reserve margin, was 363,936 Dth. As shown above in Table 21, Piedmont maintained 382,810 Dth of design day capacity, or a reserve margin of 5.0 percent. Winter season capacity entitlements declined from 45.4 Bcf to 37.2 Bcf, indicating that winter season capacity resources exceeded requirements by 14.3 Bcf, or 38 percent. Annual capacity entitlements declined from 87.5 Bcf to 50.9 Bcf, indicating that annual capacity resources, including summer storage fill requirements, exceeded requirements of 32.7 Bcf by 18.2 Bcf, or 35 percent.

A significant portion of Piedmont's 2014-2015 capacity portfolio consisted of winter season capacity. The Company's firm transportation contract with Texas Eastern is a winter-only contract, [redacted]. The capacity entitlements under the Company's firm transportation contracts with Columbia Gulf are seasonally sculpted. Of the 18.2 Bcf in excess of annual capacity entitlements, 14.3 Bcf are excess winter season capacity entitlements, and only approximately 4.0 Bcf are excess summer period entitlements. Therefore, the potential for Piedmont to rely more on winter season capacity and reduce year-round capacity is extremely limited. Moreover, Piedmont's current year-round transportation contracts do not expire until 2019. Therefore, there are no near-term opportunities to reduce the Company's year-round capacity entitlements. Finally, as noted in other sections of this Report, Piedmont has reduced the Midwestern capacity determined to be available to meet design day demands by 75,000 Dth per day. This 75,000 Dth per day has been excluded from Exeter's comparison of the Company's 2014-2015 capacity entitlements and requirements. However, Piedmont will be required to pay for this 75,000 Dth of Midwestern capacity until 2023.

5.7 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 charges that 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 injection fuel charge.

A requirement included in the Statement of Work of Exeter's review was to identify the various commodity costs charged to Piedmont under each of the Company's interstate pipeline service arrangements and those billed to Piedmont's Tennessee customers. During the course of our review, Piedmont indicated that it did not maintain information in a manner that would enable Exeter to identify the specific charges by type. However, Piedmont was assessed [redacted]. Piedmont recovers the interstate pipeline commodity charges it is assessed for the services used to serve its Tennessee customers on a dollar-for-dollar basis. The various interstate pipeline commodity rates in effect at the conclusion of the review period are identified in Table 22.

Table 22.
PIEDMONT NATURAL GAS COMPANY
Interstate Pipeline Variable Charges

TRANSPORTATION SERVICES		
Pipeline/Rate Schedule	**Commodity Charge ($/Dth)**	**Fuel Retention**
Columbia Gas		
SST	$0.0164	1.917%
Columbia Gulf		
FTS-1	$0.0121	1.156%
FTS-1 BH	$0.0121	0.367%
Midwestern Gas Transmission		
FT-A	$0.0021	1.00%
FT-B	$0.0012	
Tennessee Gas Pipeline		
FT-A 100 Leg	$0.0197	1.69%
FT-A 500/800 Leg	$0.0142	1.27%
FT-BH	$0.0142	0.20%
Texas Eastern		
FT-1	$0.0012	0.45%
SCT	$0.2474	3.61%

STORAGE SERVICES			
	Storage Variable Charge ($/Dth)		**Injection Fuel**
Pipeline/Rate Schedule	**Injection**	**Withdrawal**	**Retention**
Columbia Gas			
FSS	$0.0153	$0.0153	0.12%
Tennessee Gas Pipeline			
FS-MA	$0.0087	$0.0087	1.07%
FS-PA	$0.0073	$0.0073	1.07%

6.0 HEDGING ACTIVITY

6.1 Background and Description

The 2007 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. Piedmont's allowable hedging costs are limited to 1 percent of annual gas costs. All hedging gains and losses are reflected in the Company's purchased gas cost rates, and the gains and losses are excluded from the 1 percent cost limit. Piedmont's hedging program is designed to mitigate the impact of significant price spikes for up to 45 percent of normalized purchases. Hedges are limited to the purchase and sale of call options. Options are purchased on the New York Mercantile Exchange (NYMEX), and there are no over-the-counter (OTC) transactions.

The Company's forward-hedging horizon is one year. Piedmont hedges for both the winter and summer seasons, and the annual budget for hedging set by the 1 percent cost limit is allocated between months based on anticipated normalized purchases, including purchases for injection into storage.

Piedmont will utilize a portion of its pre-established hedging budget to purchase call options any time the futures price for any month in the 12-month forward-hedging horizon reaches specific threshold levels compared with historical prices. The Company collects historical daily prompt month settlement prices over the most recent four years, applies an inflation adjustment, and weights data for the most recent 12 months more heavily.[14] This adjusted historical price database is then segmented into deciles presented in a matrix. Current futures prices are compared against the matrix when making hedging decisions. Piedmont has established the first hedging threshold level at the point when futures prices for any month in the hedging horizon close at or below the 50th percentile of the matrix. When this occurs, Piedmont will spend 20 percent of its monthly hedging budget on call options for that month's contract. Piedmont will continue to spend an additional 20 percent of its monthly hedging budget for any month's contract any time futures prices fall into the next lower decile. For example, if futures prices for any month in the hedging horizon fall below the 40th percentile, Piedmont will spend an additional 20 percent of its monthly hedging budget on call options. If prices were to fall below the 10th percentile and into the first decile, then Piedmont will have exhausted its monthly

[14] This information is provided to the Company by Risk Management Incorporated (RMI).

hedging budget when it utilizes the last 20 percent of that budget to purchase additional call options. A sample matrix for June 2014 is presented below:

June 2014 Expiration			
Decile	Annual	Summer	Winter
[redacted]			

As a general rule, Piedmont will spend 4 percent of the decile price and spend up to 20 percent of the allowed dollars for that month. For example, if the 50th percentile is $5.00, Piedmont will spend $0.20 per Dth ($5.00 x 4 percent), and purchase calls with a strike price that cost $0.20 per Dth. If 20 percent of the allowed dollars for a given month is $50,000, that number is divided by $0.20 to arrive at a volume of 250,000 Dth to hedge. If spending 20 percent of the available dollars in any one month purchases call volumes that exceed 20 percent of the anticipated normalized purchase volume, the volume will be limited to 20 percent of the anticipated monthly purchase volume. If 20 percent of the available dollars does not purchase 20 percent of the normalized purchase volume (45 percent of normalized purchase volumes in total), the Company does not later make up the volumes even if additional funds at lower decile strike prices are available.

By way of further example, for the month of July 2012, on July 12, 2011, the Company purchased calls on [redacted] Dth for [redacted] per Dth at a strike price of [redacted] per Dth when daily NYMEX prices settled below the 50th percentile. When daily NYMEX prices settled below the 40th percentile, the Company purchased calls on an additional [redacted] Dth at a strike price of [redacted] per Dth for [redacted] per Dth on August 10, 2011. When daily NYMEX prices settled below the 30th percentile, the Company purchased calls on an additional [redacted] Dth at a strike price of [redacted] per Dth for [redacted] per Dth on August 25, 2011. When daily NYMEX prices settled below the 20th percentile, the Company purchased calls on [redacted] Dth at a strike price of [redacted] per Dth for [redacted] per Dth on October 14, 2011.[15] Finally, when daily NYMEX prices settled below the 10th percentile, the Company purchased calls on [redacted] Dth at a strike price of [redacted] per Dth for [redacted] per Dth on November 9, 2011.

If futures prices for a contract month in the forward-hedging horizon remain below the 60th percentile, Piedmont will spend 20 percent of its seasonal hedging budget on call options when the date reaches five months before the start of the season. It will continue to spend an additional 20 percent of its seasonal hedging budget on call options each subsequent month, ultimately spending up to 100 percent of its seasonal hedging budget prior to the start of a season. If all of the price-dependent hedging thresholds are not reached during the planning horizon, Piedmont will purchase calls to meet its volume target until that target is reached per the discussion above. No price- or time-dependent hedges will be implemented if futures prices are at or above the 60th percentile.

Piedmont's hedging activity during the review period is summarized in Table 23. Prior to the review period, Piedmont only hedged for [redacted].

[15] NYMEX calls are purchased in 10,000 Dth increments. The additional 10,000 Dth purchased this month is due to rounding in other purchase months.

REDACTED

Table 23.
PIEDMONT NATURAL GAS COMPANY
Summary of Review Period Call Option Hedging Activity

Hedge Month	Quantity (Dth)	Average Strike Price ($/Dth)	Average Call (Price)/Gain ($/Dth)	Call Gain/(Loss)	Fee	TOTAL COST
CALL PURCHASES						
November 2011	[redacted]					
December	[redacted]					
January 2012	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal	[redacted]					
July 2012	[redacted]					
August	[redacted]					
September	[redacted]					
October	[redacted]					
November	[redacted]					
December	[redacted]					
January 2013	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal	[redacted]					
July 2013	[redacted]					
August	[redacted]					
September	[redacted]					
October	[redacted]					
November	[redacted]					
December	[redacted]					
January 2014	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
Subtotal	[redacted]					
TOTAL - Call Purchases	[redacted]					
CALL SALES						
January 2014	[redacted]					
February	[redacted]					
March	[redacted]					
April	[redacted]					
May	[redacted]					
June	[redacted]					
TOTAL - Call Sales	[redacted]					

As indicated previously, hedging cost recovery is limited to 1 percent of the Company's total annual gas cost.[16] As shown in Table 24, Exeter's review found that Piedmont's hedging costs were less than 1 percent for each year of the review period, and that Piedmont hedged approximately 30 percent of normalized purchase volumes.

Table 24.
PIEDMONT NATURAL GAS COMPANY
Summary of Annual Hedging Costs and Limits

Plan Year	1 Percent Hedging Limit	Actual Hedging Costs
July 2011 – June 2012	[redacted]	
July 2012 – June 2013		
July 2013 – June 2014		
TOTAL		

6.2 RFP Statement of Work Requirements

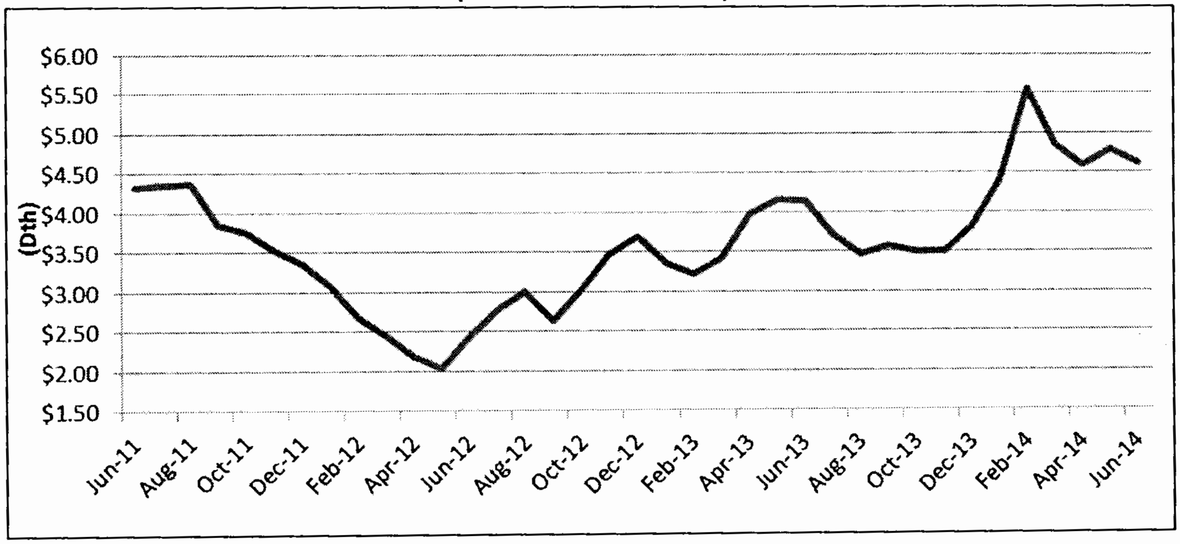
The RFP for the review of Piedmont's performance under the Plan identified for review and assessment specific aspects of Piedmont's hedging program. Those items are addressed in this section of the Report.

- *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 fluctuated during the review period. NYMEX prices settled at $4.357 per Dth for July 2011, declined steady to $2.036 per Dth by May 2012, and then generally continued to rise. The decline in prices was due in large part to the uncharacteristically mild 2011-2012 winter heating season and continued high levels of production that drove gas in storage inventories to record levels. Figure 3 presents a graph of NYMEX monthly settlement prices during the review period. Piedmont did not perform a cost-benefit analysis to support its hedging program.

[16] The recovery cap is computed from the most current audited and approved gas costs for the Company in a TRA docket as of the first day of the month, 12 months prior to the first day of the period under audit.

Figure 3.
Natural Gas Futures – NYMEX Settlement
(June 2011 – June 2014)



Source: NYMEX Settlement History – Natural Gas Futures, www.business.directenergy.com/market-insights/nymex-settlement-history.

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

  After sustaining substantial losses caused by a market decline and the sale of puts, North Carolina Public Service Commission Staff indicated their preference for a hedging policy that provided for all upside market protection from established hedges, all market participation at lower prices in a falling market, and no additional cost associated with a falling market after hedges are established. The Company subsequently chose to eliminate the sale of puts from its hedging program and to hedge exclusively by purchasing calls. This caps hedging losses to the cost of the call and achieves unlimited price protection above the strike price of the call purchased while allowing full downside market participation.

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

  As shown previously in Table 23, Piedmont purchased [redacted] Dth of calls during the review period at total costs of [redacted], or an average price of [redacted] per Dth. To purchase those calls, Piedmont incurred transaction fees of [redacted]. Of those calls purchased, Piedmont sold [redacted] Dth of those calls just prior to expiration which had value, or were "in the money." Piedmont realized a gain of [redacted] on the sale of those calls, and incurred [redacted] in transaction costs. The net impact of Piedmont's hedging program during the review period was a net loss of [redacted] or an average of approximately [redacted] per Dth sold. The only potential for losses is the costs associated with purchasing call options, including transaction fees.

- *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 annual gas costs. During the review period, Piedmont's maximum allowable spending limit was [redacted]. Piedmont's actual review period hedging expenditures were [redacted] plus [redacted] in fees (see Table 24). Piedmont's hedges were staggered over time pursuant to the procedures discussed in Section 6.1 of the Report.

- *Were there price triggers for determining hedging volumes and timing?*

  The price triggers for hedging volumes and timing were described in Section 6.1 of this Report.

- *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 with estimated costs in the absence of a hedging program.*

  Piedmont's total hedging costs for the review period, including transaction fees, were [redacted]. A gain of [redacted] was realized by Piedmont as a result of its review period hedging activities, resulting in a net cost of [redacted] per Dth sold. In addition to these tangible costs and benefits, Piedmont's hedging program provided for price mitigation in the event of a significant increase in nationwide gas prices. Because its hedging activity is based on NYMEX prices, Piedmont's hedging activities would not have provided significant mitigation for the substantial increase in Chicago citygate prices experienced during the period January to March 2014. However, as explained in Section 3.1.3 of the Report, Piedmont was largely able to avoid purchasing Chicago citygate-priced gas supplies during this period.

- *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. Exeter's review found Piedmont's documentation process satisfactory.

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

  The losses experienced by Piedmont under its hedging program during the review period were minimal, averaging [redacted] per Dth sold. The losses were the result of purchasing call options for periods during which market prices did not generally increase above call option strike prices.

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

  Piedmont employs nearly identical hedging strategies and programs in each of its service territories. Therefore, the overall impact on the North and South Carolina service territories was comparable to the [redacted] per Dth cost to Tennessee sales customers. The hedging programs in all three service territories provide for the purchase of calls, and price protection for between 22.5 and 45 percent of normalized purchase volumes. An annual gas cost limit of 1 percent is also applicable in Tennessee, which is not applicable in the Company's Carolina service territories.

  Utilities in other states that employ hedging generally rely on fixed-price purchases. Many utilities consider their hedging activities to be confidential. Utilities that utilized fixed-price purchases for hedging during the review period generally incurred losses that were greater than Piedmont's losses of [redacted] per Dth. For example, during a recent three-year period, Exeter estimates that one utility utilizing a fixed-price purchase hedging strategy lost approximately 25 cents per Dth.

- *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 6.3 of the Report.

6.3 Results and Conclusions

Piedmont adhered to the hedging activities approved under the Plan during the review period. The use of both a price-and 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 that 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.

It is Exeter's view that regulators and utilities cannot expect hedging to lower the long-term price paid for natural gas. Hedging programs take many forms and use many different tools, both physical and financial. There are no industry standards to compare hedging program results. Exeter's review of Piedmont's hedging activities did not reveal any unreasonable practices that were inconsistent with industry practices. Exeter has no recommended modifications to Piedmont's existing hedging program.

7.0 ASSESSMENT OF PIEDMONT PLAN INCENTIVES AND DESIGN

Section 7 of Exeter's Report begins with a comparison of Piedmont's Performance Incentive Plan with the gas procurement incentive mechanisms of Atmos Energy Corporation and Chattanooga Gas Company. This comparison is provided for informational purposes as well as to assist in addressing the RFP Statement of Work requirement to evaluate the balance of incentives under the Plan which is addressed in this section. This section of the Report also addresses Piedmont's Gas Supply Incentive Compensation Programs as also required in the RFP Statement of Work.

Exeter's experience in reviewing gas incentive mechanisms in jurisdictions other than Tennessee includes a now terminated program of Nicor Gas Company in Illinois, and ongoing programs of the four major natural gas utilities in Indiana (Northern Indiana Public Service Company, Vectren North, Vectren South, and Citizens Gas & Coke Utility). In a number of jurisdictions in which Exeter performs gas cost procurement reviews, capacity release revenues, off-system sales margins, and AMA fees are subject to sharing with the utility. These jurisdictions include Delaware, Louisiana, Massachusetts, Ohio, and Pennsylvania.

7.1 Comparison of Piedmont Plan with Similar Incentive Mechanisms of Other Tennessee Natural Gas Distribution Companies

7.1.1 Piedmont Performance Incentive Plan

Piedmont's Plan consists of three components: (1) a commodity procurement cost component; (2) a supplier reservation fee component; and (3) a capacity management component. Under the commodity procurement cost component of the Plan, Piedmont's actual total monthly citygate (delivered) commodity cost of gas is compared to costs based on a Monthly Benchmark Index Price. 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. The commodity procurement cost component provides for a 75 percent sales customer and 25 percent Company sharing of the difference between actual and benchmark costs. Piedmont's Plan does not include a deadband in calculating sharing amounts.

Under the commodity procurement cost component of the Plan, separate benchmarking procedures are provided for in the MBIP for monthly, daily, and citygate purchases. The monthly benchmark is based on a price that reflects published index prices weighted by the amount of firm interstate pipeline receipt point capacity that Piedmont reserves at each of its purchase locations. For example, if 60 percent of Piedmont's interstate pipeline capacity portfolio consisted of TGP capacity and the remaining 40 percent was Columbia Gulf capacity, Piedmont's benchmark for monthly purchases would be based on a 60/40 percent weighting of TGP and Columbia Gulf monthly index prices, adjusted for variable and fuel charges. Daily purchases are benchmarked against the actual daily published index prices for the purchase location plus the applicable variable and fuel charges. For citygate purchases, those purchases that are priced based on a production area commodity index price are benchmarked based on the applicable production area index prices plus the maximum applicable interruptible transportation and variable fuel charges for the interstate pipeline delivering the gas to Piedmont's citygate. Those citygate purchases that were priced based on a citygate delivered price are benchmarked based on the citygate delivered cost of the supplies that were displaced by the citygate purchases. Piedmont's Plan does not provide the sharing of avoided demand charges as provided for under the subsequently discussed incentive mechanisms of Atmos and Chattanooga Gas. Typically, the rewards realized by Piedmont under the commodity procurement cost component of the Plan are generated by monthly purchases.

Under the supplier reservation fee component of the Plan, Piedmont is entitled to recover 100 percent of its gas supply reservation fees with no gain or loss potential. The capacity management component of Piedmont's Plan provides that the revenues (margins) realized from capacity release and off-system sales activities, as well as AMA fees, be subject to the same 75 percent ratepayer / 25 percent Piedmont sharing procedures as commodity procurement cost component savings/losses. Piedmont's Plan includes a $1.6 million sharing cap.

7.1.2 Atmos Performance Based Ratemaking Mechanism

Atmos' Performance Based Ratemaking Mechanism (PBRM) consists of a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a monthly benchmark against which Atmos' monthly commodity cost of gas is compared. The monthly benchmark is based on published index prices for the locations at which Atmos' gas supplies are purchased and the type of purchase. That is, monthly purchases are benchmarked against monthly index prices and daily prices are benchmarked against daily index prices. For citygate purchases, the benchmark is adjusted for the avoided pipeline demand transportation charges that would have been paid for the delivery of gas to the citygate, less any demand charges paid to the supplier providing the service. If Atmos' total monthly commodity cost of gas falls within a deadband of the total monthly benchmark amount, there are no incentive savings or costs to share. If Atmos' total monthly commodity cost of gas is below the deadband, Atmos is permitted to retain, as a reward, 50 percent of the difference. If the total monthly commodity cost of gas is above the deadband, Atmos is denied recovery of 50 percent of the difference. During the period most recently reviewed by Exeter (April 1, 2011 through March 31, 2014), all of the Gas Procurement Incentive Mechanism savings achieved by Atmos were attributable to avoided demand charges.

Under the Capacity Management Incentive Mechanism, to the extent Atmos is able to release transportation or storage capacity, or achieve savings from off-system sales, the associated revenues and margins are shared by Atmos' sales customers and Atmos on a 90/10 percent basis, respectively. During the period most recently reviewed by Exeter, all Capacity Management Incentive Mechanism savings were attributable to AMA fees. Under the PBRM, Atmos is subject to an overall combined annual cap on incentive savings or costs under both incentive mechanisms of $1.25 million. Atmos' share of PBRM savings was limited by the $1.25 million cap during each plan year of the period most recently reviewed by Exeter.

7.1.3 Chattanooga Gas Performance Based Ratemaking Mechanism

The gas cost incentive plan under which Chattanooga Gas operates is also referred to as the Performance Based Ratemaking Mechanism. Chattanooga Gas also operates under a separate Interruptible Margin Credit Rider (IMCR) that addresses the sharing of revenues (margins) generated from capacity release and off-system sales activities, as well as AMA fees.

Under Chattanooga Gas' PBRM, each month, Chattanooga Gas' actual commodity cost of gas is compared to a monthly benchmark amount. For monthly and daily purchases, the benchmark amount is based on the applicable published index price for the location at which gas is purchased. For citygate purchases, Chattanooga Gas' PBRM provides for the inclusion of the avoided transportation charges that would have been paid if upstream capacity was purchased versus the demand charges paid to the supplier.[17] If Chattanooga Gas' total actual commodity gas costs for a plan year do not exceed the total benchmark amount by 1 percent, its' commodity gas costs are deemed prudent and the audit required by TRA Administrative Rule 1220-4-7-.05 is waived. If, during any month of a plan year, Chattanooga Gas' commodity gas costs exceed the benchmark amount by greater than 2 percent, it is required to file a report with the TRA fully explaining why costs exceeded the benchmark. There is no sharing of any savings or losses under Chattanooga Gas' PBRM. Exeter's most recent review of Chattanooga Gas' PBRM encompassed the period April 1, 2010 through March 31, 2013. For this review period, Chattanooga Gas' actual gas costs exceeded benchmark costs by approximately $150,000, which was less than 1 percent of benchmark gas costs. Chattanooga Gas' commodity gas costs did not

[17] Chattanooga Gas has interpreted upstream transportation charges to include variable charges, while Atmos has interpreted this provision to include demand charges.

exceed benchmark costs by 2 percent in any month during the period most recently reviewed by Exeter.

Chattanooga Gas' IMCR provides for a 50 percent ratepayer sharing of the revenues (margins) generated from capacity release and off-system sales activities, as well as AMA fees. There is no cap on the amounts eligible for sharing under the IMCR.

7.2 Balance of Plan Incentives

Piedmont is able to generate savings and realize rewards under the commodity procurement cost and capacity management components of the Plan. Rewards under the Plan are capped at $1.6 million. The RFP Statement of Work included the requirement to evaluate the balance of incentives between Piedmont and its sales customers under the Plan.

7.2.1 Capacity Management Component

The capacity management component of the Plan addresses the revenues (margins) realized from capacity release and off-system sales activities, as well as AMA fees, and provides for a 75 percent sales customer / 25 percent Company sharing. More than 90 percent of the revenues available for sharing under the capacity management component during the review period were generated from AMA fees. The remaining revenues were from production area off-system sales which did not utilize interstate pipeline capacity. Piedmont did not engage in capacity release or non-production area off-system sales activities during the review period because the capacity necessary to perform these activities was released to an Asset Manager under an AMA. It is Exeter's experience that in other jurisdictions, sharing percentages which range from 90 percent customer / 10 percent utility to 75 percent customer / 25 percent utility have been adopted for AMA fees, with the lower end of the sharing range for the utility being more prevalent. With respect to capacity release revenues and off-system sales margins, 75 percent customer / 25 percent utility sharing percentages are common in other jurisdictions. Exeter concludes that there is a relatively reasonable balance of incentives between Piedmont and customers under the capacity management component of the Plan.

7.2.2 Commodity Procurement Cost Component

The commodity procurement cost component of the Plan also provides for a 75 percent customer / 25 percent Company sharing of savings. Different benchmarking procedures are applicable for monthly purchases, daily purchases, and other purchases under the commodity procurement cost component of the Plan. The balance of incentives for each type of purchase is addressed separately.

As previously explained, Piedmont's monthly purchases delivered under firm and interruptible transportation arrangements are evaluated based on a benchmark that reflects published index prices weighted by the amount of firm interstate pipeline receipt point capacity Piedmont reserves at each purchase location. Piedmont realizes a reward for monthly purchases if those purchases are made at the lowest-cost receipt points. The forecasted relative price relationship for the various receipt point locations is generally known by all participants in the natural gas market. Other utilities operating under traditional regulation maximize the purchase of gas supplies at the lowest-cost receipt points, as Piedmont did during the review period. For doing so, Piedmont earned a reward of approximately [redacted] during the review period. Exeter's most recent review of the gas cost incentive plans of Atmos and Chattanooga Gas revealed that each of these utilities also maximizes the purchase of gas supplies at the lowest-cost receipt points. However, neither utility realizes a reward for doing so under their respective gas cost incentive mechanism. Therefore, Exeter concludes that the monthly benchmarking procedures under the commodity procurement cost component of the Plan is unbalanced in the Company's favor.

Daily purchases delivered under firm and interruptible transportation arrangements are benchmarked against the actual published index prices for the purchase location. Piedmont did not earn rewards during the review period under the Plan for daily purchases. The 75 percent sales customer / 25 percent Company sharing procedures adopted for daily purchases under the commodity procurement cost component of the Plan are somewhat conservative in that similar incentive mechanisms in other jurisdictions have adopted 50 percent customer / 50 percent utility sharing procedures.

As previously described in Section 3.1.3 of the Report, one of the citygate purchase arrangements entered into by Piedmont during the review period provided for the delivery of supplies by [redacted]. Under this arrangement, Piedmont paid [redacted] per Dth. These citygate purchases were made to displace significant quantities of higher-cost [redacted] delivered supplies. However, after accounting for Piedmont's share of savings under the Plan, customers were charged more for these citygate deliveries than if the gas was transported under Piedmont's [redacted] capacity. While the additional costs charged to ratepayers were relatively small (approximately [redacted]), Exeter finds that an appropriate balance of incentives does not exist if customers are charged more for gas when lower-cost supplies are purchased than when higher-cost supplies are purchased.

In addition to the [redacted] delivered citygate supplies, as previously explained in Section 3.1.3, Piedmont achieved savings of nearly [redacted] by purchasing replacement supplies for the Midwestern firm gas supplies for which it had contracted during the third year of the review period. Absent the $1.6 million Plan cap, Piedmont would have realized a reward of nearly [redacted] under the Plan for these replacement purchases. On January 28, 2014 alone, Piedmont was able to achieve savings of [redacted] and would have realized a reward of [redacted] without the Plan cap. The savings associated with these replacement citygate purchases were calculated based on Chicago citygate index prices rather than the location at which the gas was actually purchased. The tariff language discussing the benchmarking of these purchases under the Plan is not clear as to how these citygate purchases should be benchmarked. If the information were available to benchmark these citygate purchases based on the applicable production region index price, an index price for the upstream pipeline receipt point, or an index location near Piedmont's system, the savings calculated under the Plan would have likely been much smaller or potentially non-existent. Nevertheless, Exeter believes that Piedmont's efforts in securing lower-cost replacement supplies during the review period is the type of behavior that should be encouraged and rewarded under a gas cost incentive mechanism. However, a reward of [redacted] could be considered excessive.

7.2.3 $1.6 Million Plan Cap

Consistent with the findings of a study evaluating gas procurement incentive mechanisms conducted by the National Regulatory Research Institute (NRRI), Exeter concurs that caps can weaken or eliminate incentives.[18] [redacted]. However, Exeter believes that the savings associated with monthly purchases that Piedmont is able to generate under the Plan are achievable under traditional regulation and should not result in a reward for Piedmont. In addition, it appears that under certain circumstances, citygate purchases can result in increased costs for customers, and the Company's off-system sales activities can inappropriately increase the gas costs of sales customers under the current structure of the Plan. Finally, the benchmarking procedures applicable for citygate purchases are not adequately specified in the tariff language describing the Plan. For these reasons, Exeter recommends that the $1.6 million cap be maintained.

7.3 Gas Supply Incentive Compensation Program

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[19] The incentive programs in place in North and South Carolina provide for a 75 percent customer / 25 percent Company share of margins from secondary marketing activities similar to those included in the capacity management component of the Plan. The Carolina incentive programs do not include a component similar to the commodity gas cost procurement component of the Plan. There are no revenue sharing caps under the Carolina programs.

8.0 FINDINGS OF FACT AND AREAS OF CONCERN

Findings of fact from Exeter's triennial review are as follows:

- Piedmont purchased transportation and storage services from five interstate pipelines during the review period.
- Piedmont released its interstate pipeline firm transportation and storage capacity to third parties under Asset Management Agreements during the review period.
- Piedmont purchased several delivered-to-citygate supply services during the review period.
- Piedmont served an average of 169,999 sales and transportation customers during the review period, and total system throughput averaged 29,000,000 Dth.
- All of Piedmont's gas supply contracts with supplier reservation fees during the review period included [redacted].
- Plan-determined savings during the review period were [redacted], and Piedmont's share of savings was [redacted].
- Savings of [redacted] were realized under the commodity procurement cost component of the Plan on monthly purchases, and savings of [redacted] were realized on citygate purchases. The savings on citygate purchases during the review period were primarily realized during the winter of 2013-2014. [redacted].
- Piedmont earned a reward of [redacted] from its asset management arrangements and off-system sales activities during the review period.
- Piedmont engaged in no transactions with affiliates during the review period.
- The capacity management component of the Plan provides a reasonable balance of incentives between Piedmont and its customers.
- Piedmont's review period storage activity was reasonable.
- Piedmont's review period gas supply purchases delivered under firm transportation arrangements were reasonable.
- Piedmont's revised design day forecasting procedures are reasonable.

- Piedmont made significant changes to its design day capacity portfolio after the conclusion of the review period for the winter of 2014-2015.

- Piedmont's efforts to avoid the purchase of high-cost Chicago index-priced supplies were successful and extremely beneficial to ratepayers even though they resulted in no reward under the Plan.

- 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.

- Based on Piedmont's capacity portfolio for the winter of 2014-2015, the potential for the Company to rely more on winter season capacity and reduce year-round capacity is extremely limited.

- Piedmont's use of a partially price- and partially time-dependent approach to hedging and hedging through call options is reasonable.

- 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 observed industry practices.

- [redacted].

Exeter's review noted the following areas of concern and potential areas of improvement under the Performance Incentive Plan:

- The current design of the monthly purchase benchmark included in the Monthly Benchmark Index Price results in gas cost savings that would have been realized without the existence of the Plan. With the reduction in Midwestern design day capacity to 25,000 Dth per day, the savings associated with monthly purchases should significantly decline in the future.

- A number of Piedmont's off-system sales transactions had an adverse impact on sales customers during the review period.

- The procedures used to benchmark monthly and daily citygate purchases are not clearly defined in the tariff language describing the Plan, and modifying the Plan language to provide further clarification should be considered.

- The purchase of lower-cost delivered supplies which are benchmarked based on interruptible transportation rates can lead to higher costs to sales customers than higher-cost purchases delivered under firm transportation arrangements due to the sharing provisions of the Plan. Changes to the Plan that eliminate this counter-intuitive result should be considered.

- Piedmont should evaluate including wind speed and prior day temperature independent variables in its design day forecast model.

- Piedmont should monitor whether it could generate more revenue through off-system sales and capacity release activities on its own rather than through an AMA, particularly if AMA fees decline in the future.

- Piedmont excluded its Columbia Gulf backhaul and certain Midwestern design day capacity from its monthly purchase benchmark calculations during the review period. The tariff language describing the Plan does not appear to provide for capacity exclusions, but the Plan description could be clarified to further address potential capacity exclusions. Piedmont's review period capacity exclusions decreased Plan-determined savings.

- The modifications that were made to the Plan effective March 1, 2012 provided for the inclusions of interruptible transportation delivered supplies in the monthly benchmark. It is Exeter's understanding that this was not the intent of the IT language modification and could result in high-cost supplies inappropriately being included in the month's benchmark, which Piedmont has no intention of purchasing. Exeter recommends that changes to the Plan language be considered to address this potential.

- Due to the number of concerns with the current structure of the Plan described in the Report, Exeter recommends that the $1.6 million Plan cap be maintained.

APPENDIX A:

PIEDMONT NATURAL GAS COMPANY

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 (Plan Year) will begin July 1st. 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,

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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 negotiate/obtain firm capacity, interruptible capacity and/or gas supply pursuant to such plan.

Commodity Costs

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

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

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, negotiated FT, and IT 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 I; 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 ~~maximum~~ firm transportation (FT) and interruptible transportation (IT) commodity transportation charges and fuel retention to the city gate under the Company's FT, negotiated FT, and IT service agreements.[3]

[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.

[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.

EFFECTIVE: ~~November 22, 2010~~ March 1, 2012

K = the fraction (relative to total maximum daily contract entitlement) of the Company's total firm, negotiated firm, and interruptible 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, negotiated FT, and IT 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, negotiated FT, and IT 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.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using the Company's firm, negotiated firm, and interruptible 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

[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).

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.[6] 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, and the costs of financial instruments.

All costs related to hedging transactions, in addition to all gains and losses from hedging transactions, shall be credited/debited to the ACA account in the respective month that each hedging transaction closes. Costs related to hedging transactions that are incurred prior to the month that the hedging transaction closes shall be temporarily recorded in a separate, non-interest bearing account for tracking purposes.

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 entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its

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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.

6 One percent (1%) of total annual gas costs, for the purposes of establishing a recovery cap, shall be computed from the most current audited and approved gas costs for the Company in a TRA docket as of the first day of the month, 12 months prior to the first day of the period under audit.

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 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 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 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.