ORIGINAL

Equitable Statement No. 1
Docket No. R-00061295
Witness: Robert M. Narkevic

EQUITABLE GAS COMPANY

Prepared Direct Testimony of
Robert M. Narkevic
(Prepared April 2006)

PREPARED DIRECT TESTIMONY OF ROBERT M. NARKEVIC

I. Witness Background

Q. *PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.*

A. My name is Robert M. Narkevic. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company ("Equitable" or the "Company"), a division of Equitable Resources, Inc., as Manager of Rates.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE IN THE GAS INDUSTRY.

A. I graduated from Robert Morris College in 1981 with a Bachelor of Science degree in Accounting, and I am a Certified Public Accountant. I began my career with Columbia Gas in 1981 as an Internal Auditor located in Pittsburgh. I was then promoted to the General Auditing department in 1985 as a General Auditor and relocated to the headquarters of Columbia in Wilmington, Delaware. After three years as a General Auditor I left Columbia Gas and commenced employment with Equitable Resources, Inc. in 1988 as a Senior Internal Auditor. In 1991, I became the Manager of Billing for Equitable and retained that position for two years. In that capacity, I prepared billing lag data for the Company's cash working capital claim in its 1991-92 general rate proceeding at Docket No. R-912164. In 1995, I became the Manager of General Accounting. In this capacity, I was responsible for preparation of the Company's Annual Reports to the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia and the Kentucky Public Service Commission, for the years ended 1994 and 1995. During those years, I was also responsible for preparing and filing monthly reports to these same Commissions. In January 1996, I became Manager of Financial Accounting. As Manager of Financial Accounting I was responsible for the financial activities of the Equitable Gas Company Division. My principal duties as Manager of Financial Accounting were to plan, direct, and coordinate the preparation of financial statements, budgets, forecasts, and variance reports related to Equitable. I also directly communicated with external, internal, and regulatory auditors on an on-going basis, while they performed their various audit functions. In January 2001 I became the Manager of Rates for Equitable.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for the management of Equitable's rate functions including the development of and support of Equitable's rates and tariffs for Pennsylvania, West Virginia and Kentucky.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY ON BEHALF OF EQUITABLE?

A. Yes. I previously submitted testimony before this Commission in Equitable's 1996/1997 General Rate proceeding at Docket No. R-00963858, and Equitable's last five 1307(f) proceedings at Docket Nos. R-00016132, R-00027135, R-00038166, R-00049154 and R-00050272.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. First, I will briefly address the components of the Company's 2006 Section 1307(f) filing which I am sponsoring and provide a brief description of Equitable Gas Company. Next, I will describe the Company's 1307(f) filing and explain the computation of Equitable's Purchase Gas Cost (PGC) rate as set forth in Item 53.64(a) of the 2006 definitive filing. I will also discuss corresponding tariff modifications resulting from the PGC rate change, as well as several administrative changes to our existing tariff. Finally, I will discuss the change in the recovery of the cost of no-notice service.

III. Responsibility for the Filing

Q. WHICH COMPONENTS OF THE COMPANY'S 2006 1307(f) FILING ARE YOU SPONSORING?

A. The specific sections of the filing which I am sponsoring are listed on Attachment RN-1 to my testimony. The majority of these sections are self-explanatory. However, I will answer any questions which may arise during the course of this proceeding concerning these sections.

IV. Description of Company

Q. PLEASE DESCRIBE EQUITABLE.

A. Equitable is the regulated local distribution company division of Equitable Resources, Inc. The Company's principal offices are located at 225 North Shore Drive, Pittsburgh, PA 15212.

As of December 31, 2005, Equitable served 257,236 residential, commercial and industrial customers in the City of Pittsburgh and adjacent territories in Allegheny, Armstrong, Butler, Clarion, Fayette, Greene, Indiana, Jefferson, Washington and Westmoreland Counties in Southwestern Pennsylvania. It also serves 13,474 residential, commercial and industrial customers in West Virginia, and approximately 3,702 farm-tap customers in Eastern Kentucky.

Of the total customers served by the Company in Pennsylvania as of December 31, 2005, 239,478 were residential customers, 17,584 were commercial customers and 174 were industrial customers.

V. Description of Filing

Q. PLEASE DESCRIBE THE COMPANY'S FILING IN THIS PROCEEDING.

A. The Company has projected a decrease in its PGC to sales customers by approximately $72 million annually, or a decrease of $2.98 per Mcf effective October 1, 2006. The annual bill of an average residential customer using 98 Mcf per year will decrease by approximately $24.35 or 15.8%.

Q. DID YOU PREPARE ITEM 53.64(a) IN THE COMPANY'S 2006 1307(f) FILING?

A. Yes. Item 53.64(a) contains two sections. Section I provides the supporting schedules detailing the computation of Equitable's proposed 2006 PGC rate, and Section II contains the Company's proposed tariff sheets. Section I is divided into four sub-sections titled Parts A through D. Section I, Part A, consists of Sheets 1 through 6 and includes the calculations for the C-Factor, E-Factor and total tariff sales rates proposed in the filing. Section I, Part B, consists of Sheets 1 through 8 and contains the projected period volumes and associated gas costs. Section I, Part C, consists of Sheets 1 through 7 and details the interim period over/under collections, volumes and associated gas costs. Section I, Part D, consists of Pages 1 through 4 and details the reconciliation period over/under collections, volumes and associated gas costs.

Q. PLEASE DESCRIBE THE SHEETS CONTAINED IN SECTION I, PART A.

A. Sheet 1 of Section I summarizes the computation of Equitable's proposed 2006 PGC rate of $11.28/mcf and shows the associated decrease in the purchased gas costs of $2.98/mcf to be reflected in tariff rates. Sheets 2 and 3 summarize the development of the "E" Factor amount reflected in the proposed 2006 PGC. The Company's filing reflects a projected net undercollection of $18 million or an E-Factor rate of $0.74 per Mcf. Sheet 4 indicates that the Company is including no supplier refunds in this "E" factor. The interest on undercollections is calculated at the legal rate of interest set forth in 41 Pa.C.S. § 202 and the interest on overcollections is calculated at the legal rate of interest plus two percent (2%) as required by 66 Pa.C.S. § 1307(f)(5). Sheet 5 develops the calculation of interest on over/under collections. The total interest due the Company included in the filing is $1,452,072. Sheet 6 illustrates the proposed tariff sales rates to be effective October 1, 2006, excluding customer meter charges.

Q. PLEASE DESCRIBE THE SHEETS CONTAINED IN SECTION I, PART B.

A. Sheets 1 through 8 relate to the determination of the "C" Factor, which is the projected cost component of the Company's proposed rate. Sheet 1 shows the projected customer requirements and associated supply for the 2006 PGC application period, while Sheets 2 through 4 detail the computation of the related supply costs. Sheets 5 and 6 provide the computation of the Company's estimated cost of gas injected into storage as of October 31, 2006, and Sheets 7 and 8 provide the computation of the Company's estimated cost of gas injected into storage as of September 30, 2007. Since the Company does not reflect the cost of gas injected into storage for PGC purposes until that gas is withdrawn from storage, the Company's proposed 2006 PGC does not include the costs listed on Sheets 7 and 8, but does include the costs listed on Sheets 5 and 6 since the gas will be withdrawn during the projected period winter season.

Q. PLEASE DESCRIBE THE SHEETS CONTAINED IN SECTION I, PART C.

A. Sheet 1 of 7 develops the actual/estimated undercollection for the nine-month period ending September 30, 2006 (Interim Period). The monthly purchased gas costs shown on Sheet 1, Column (4) are developed on Sheets 2 through 7. Sheets 2 and 3 provide the Company's actual purchased gas costs and demand costs, respectively, for January and February 2006, while Sheet 4 provides the projected customer demand and associated supply for the period March 2006 through September 2006. Sheets 5 through 7 detail the development of the purchased gas costs associated with the projected PGC customer demand shown on Sheet 4.

Q. PLEASE DESCRIBE THE SHEETS CONTAINED IN SECTION I, PART D.

A. Sheet 1 provides the computation of the actual net undercollection for the twelve months ended December 31, 2005 (reconciliation period), while Sheets 2 and 3 detail the development of reconciliation period purchased gas costs. Sheet 4 summarizes the Company's purchases for storage injection during the reconciliation period and develops the monthly average unit cost of gas in storage. This unit cost is used in calculating the cost of gas withdrawn from storage during the 2005-2006 winter season..

Q. PLEASE EXPLAIN THE COMPUTATION OF THE ACTUAL NET UNDERCOLLECTION FOR THE RECONCILIATION PERIOD SHOWN ON SHEET 1 OF SECTION I, PART D.

A. The actual net undercollection of ($23,398,241) is computed by subtracting the estimated net undercollection already included in rates for the reconciliation period of ($15,100,063) which is reflected in the "E" Factor component of the Company's currently effective PGC rate, from the actual undercollection for the twelve month reconciliation period of ($38,498,304). The PGC revenue shown under Column (3) of Sheet 1 is computed by multiplying PGC sales volumes, Column (1), by the "C" Factor component of the applicable PGC rate, Column (2).

Four "C" Factor Components of the PGC rates were in effect for Equitable during the reconciliation period. On October 1, 2004 the Total Sales rate of $12.98 per Mcf was effective for service rendered on and after October 1, 2004, which remained in effect through March 31, 2005. On April 1, 2005 the Total Sales rate was increased to $13.63 per Mcf and remained in effect through September 30, 2005. On October 1, 2005 the Total Sales rate increased to $16.95 per Mcf and remained in effect through the end of 2005.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE RECONCILIATION PERIOD PURCHASED GAS COST.

A. Sheets 2 and 3, of Part D, detail the development of the reconciliation period monthly purchased gas costs used on Sheet 1 to compute monthly over/(under) collections. Sheet 2 is a summary of all purchased gas costs, demand and commodity, for each month of the reconciliation period. Sheet 3 is the detail of the demand costs, less capacity release credits, which is included on Sheet 2, line 12. These costs were computed by subtracting the credits shown on lines 14 through 17 of Sheet 2 from the Company's total purchased gas costs shown on line 13 of Sheet 2. All credits are described below:

a) **Standby Service** - The Company credits all standby service charge revenue in computing 1307(f) purchased gas costs.

b) **Cash-Out** - Purchased gas commodity costs assigned to the Company's cash-out tariff provisions continue to be credited to the PGC.

c) **Off System/Capacity Release Sharing** - Pursuant to a Commission Order in Docket No. R-00050272 Equitable will share net revenues generated by off-system transactions, as well as capacity release revenues, at a level of 75% to the PGC customers and 25% retained by the Company, for the period October 1, 2005 through September 30, 2006.

d) **PBR/Balancing Credit** - Pursuant to Commission Orders in Docket Nos. R-00016132, R-00027135, R-00038166, and R-00049154 various guaranteed credits have been credited to the PGC for the period October 1, 2001 through September 30, 2005, in lieu of the sharing mechanisms previously applied to off system sales net revenues and non-customer choice capacity release revenue (PBR Design No. 1). The last of these guaranteed credits, equaling $1.75 million, is reflected in the month of September 2005. In addition, pursuant to the Commission's Order in Docket No. R-00027135, an additional guaranteed credit of $500,000 per year has been credited during each 12-month period beginning October 1, 2002 through September 30, 2005 related to the Company's PBR Design No. 2. The last credit of $500,000 is also reflected in the month of September 2005. Beginning October 1, 2005, pursuant to the Commission Order in Docket No. R-00050272, this fixed credit is replaced by the sharing mechanism discussed above. Additionally, the

Commission Order in Docket No. R-00050272 required that no-notice costs be recovered from PGC rates and the balancing charge paid by all customers be credited to the PGC. These credits are reflected for the months of October *2005 through* December 2005.

VI. The Elimination of PBR Design No. 2

Q. PLEASE DESCRIBE THE COMPANY'S PBR DESIGN NO. 2.

A. During Equitable's 2002 Section 1307(f) proceeding at Docket No. R-00027135, the Commission approved a guaranteed credit proposal and a performance-based incentive that rewarded Equitable if it efficiently managed its recovery of no-notice service costs used by Equitable to balance the difference between natural gas deliveries and customers' consumption. The Company referred to this incentive as PBR Design No. 2. Under the Commission approved settlement for PBR Design No. 2 in the 2002 1307(f) proceeding, Equitable's base rate balancing charge was continued at its then-current level of $0.18/Mcf while the charge to commercial and industrial ("C&I") customers was increased from $0.18/Mcf to $0.28/Mcf. Equitable was allowed to discount the C&I balancing charge for competitive customers. At the same time, Equitable was required to provide a guaranteed $500,000 of revenue from this increased balancing charge as a credit to PGC customers. No limit was placed on the amount of balancing charge revenue the Company may retain after reflecting the guaranteed credit amount. The $500,000 credit was reflected in the annual 1307(f) filing and continued until September 30, 2005 without reconciliation on a cost or volumetric basis. To clarify, PBR Design No. 2 was a guaranteed credit of $500,000 to the PGC.

Q. DID THE COMPANY ATTEMPT TO EXTEND PBR DESIGN NO. 2 PAST ITS EXPIRATION DATE OF SEPTEMBER 30, 2005?

A. Yes. The Company attempted to extend PBR No. 2 in its 2005 1307(f) proceeding at Docket No. R-00050272.

Q. WAS THE COMPANY SUCCESSFUL IN ITS ATTEMPT TO EXTEND PBR DESIGN NO. 2?

A. No.

Q. IS THE $500,000 ANNUAL CREDIT TO THE PGC APPLICABLE AFTER SEPTEMBER 30, 2005?

A. No.

Q. HOW THEN ARE THE BALANCING CHARGES AND THE EQUITRANS NO-NOTICE SERVICE COSTS BEING TREATED IN THIS 1307(F) PROCEEDING?

A. Beginning October 1, 2005 the Equitrans no-notice costs and corresponding balancing charges are being treated in accordance with the Commission's Order in Docket No. R-00050272, which requires that no-notice costs be recovered from PGC rates, and the balancing charge paid by all customers be credited to the PGC.

Q. HOW IS THIS TREATMENT REFLECTED IN THE FILING?

A. Section 1, Part D, Page 3 of 4, line 2 of the Filing, reflects the cost of the Equitrans no-notice service for the months of October through December of 2005. The Equitrans no-notice costs are also reflected in demand costs for the period January 2006 through September 2007. Additionally, a credit to the PGC is reflected for balancing charges on Section 1, Part D, Page 2 of 4, line 17 for the months of October through December of 2005. Credits for actual and estimated balancing charges are also reflected for the period January 2006 through September 2007 in the filing.

Q. PLEASE EXPLAIN SECTION II OF ITEM 53.64(a).

A. Section II of Item 53.64(a) contains the proposed tariff sheets which reflect the Company's currently effective rates adjusted for the proposed PGC rate decrease. The proposed tariff sheets reflect decreases in the PGC rate schedules, Rider A, Migration Rider B, and the Company's standby service rate schedules. The proposed tariff sheets also reflect modifications to Page 35 of the Company's rules and regulations for security deposits for Pool Administrators; Pages 61, 67, 69, and 70, to remove unnecessary language; Page 62, to correctly include in the tariff the application of Rider D to Rate FDS; Pages 78 and 79 of the Company's standby service tariff to remove language no longer applicable to the service, as well as the rate decrease to the standby rate.

Q. PLEASE EXPLAIN THE CHANGE ON PAGE 35.

A. The Company's current tariff calculates a security deposit for pool administrators equal to the aggregated pool maximum daily quantity times $4.00 per Dth times 60 days. The Company is proposing to change the $4.00 rate to a publicly published market rate consistent with the Company's balancing requirements and the calculation of cash-in and cash-out rates, which will provide the Company the option of requesting a security deposit that approximates the current price of natural gas.

Q. PLEASE EXPLAIN THE CHANGES ON PAGES 61, 67, 69, AND 70.

A. The Company's current tariff pages 61 (Rate FDS – Firm Delivery Service) and 67 (Rate DDS – Daily Delivery Service) include meter charges for levels of annual throughput that are inconsistent with the availability of the rate schedules. The Company is proposing to eliminate the inconsistency. Pages 69 and 70 (Rate FPS – Firm Pooling Service) includes duplicative language which the Company is proposing to eliminate.

Q. PLEASE EXPLAIN THE ADDITIONAL CHANGES ON PAGES 78 AND 79.

A. The Company's current tariff refers to winter and year round services. These services were changed eliminating the two separate services and combining them into one service effective for the full year. The Company's proposed changes eliminate the references to winter or year round, as well as eliminating one reference to gross receipts tax that is no longer applicable.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

ATTACHMENT RN-1

Sections of the 1307(f) Filing R. M. Narkevic is sponsoring:

Item 53.64 (a), Section I

Part A: Sheet 1 of 6
Part A: Sheet 2 of 6
Part A: Sheet 3 of 6
Part A: Sheet 4 of 6
Part A: Sheet 5 of 6
Part A: Sheet 6 of 6

Part B: Sheet 1 of 8, lines 1-10

Part C: Sheet 1 of 7
Part C: Sheet 2 of 7
Part C: Sheet 3 of 7
Part C: Sheet 4 of 7, lines 1-10

Part D: Sheet 1 of 4
Part D: Sheet 2 of 4
Part D: Sheet 3 of 4
Part D: Sheet 4 of 4

Item 53.64(a), Section II

Item 53.64 (c) (4)
Item 53.64 (c) (8)
Item 53.64 (c) (9)
Item 53.64 (c) (11)

Item 53.64(i)

ORIGINAL

Equitable Statement No. 1-R
Docket No. R-00061295
Witness: Robert M. Narkevic
JUN 16 2006

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JUN 21 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Robert M. Narkevic

(Prepared in June 2006)

PREPARED REBUTTAL TESTIMONY OF ROBERT M. NARKEVIC

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Robert M. Narkevic. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company, a division of Equitable Resources, Inc., as Manager of Rates.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted direct testimony that has been marked as Equitable Statement No. 1.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony I will attempt to clarify the Company' s position regarding the matter raised in the direct testimony of Office of Small Business

Advocate (" OSBA") witness Brian Kalcic concerning the Company's expected refund from Equitrans, LP (" Equitrans") and its application to PGC rates.

III. Equitrans Refund

Q. DOES THE COMPANY EXPECT TO RECEIVE A REFUND FROM EQUITRANS?

A. Yes. Equitrans filed a general rate case (Docket No. RP04-97) at the FERC on December 1, 2003 and has been collecting its filed-for rates from Equitable, subject to refund, since September 1, 2004. On April 5, 2006 FERC issued an order approving a settlement agreement between Equitrans and the various parties which should provide a substantial refund for Equitable's customers.

Q. WHEN DO THE NEW SETTLED RATES BECOME EFFECTIVE?

A. The new rates became effective June 1, 2006.

Q. WHEN DOES EQUITABLE EXPECT THE REFUND?

A. Equitrans is required to provide the refund to its customers no later than sixty days after the effective date, which means Equitable should receive the refund by no later than August 1, 2006.

Q. DOES EQUITABLE KNOW THE EXACT AMOUNT OF THE EQUITRANS REFUND?

A. No, not at this time.

Q. HOW DOES EQUITABLE PLAN TO APPLY THE EQUITRANS REFUND.

A. The Commission' s Order entered December 15, 2005 at Docket No. P-00052192 provided that the first $7 million of the Equitrans refund was to be applied to a program to assist low income customers. A proportional share, estimated to be approximately $2 million, of any refund in excess of $7 million was then to be applied to commercial and industrial customers (" C & I customers"). Any amount remaining after the initial $7 million and the proportional share to C & I customers was to be a general credit to gas costs.

Q. DOES MR. KALCIC AGREE WITH THE MANNER IN WHICH THE REFUND WILL BE APPLIED?

A. No, not entirely. I believe that Mr. Kalcic and the Company have a slightly different idea of the amount of the C & I credit and the manner in which the funds will be applied. I believe Mr. Kalcic is expecting exactly $2 million to be applied to C & I customers. Mr. Kalcic states in his testimony that " the Company explains that it intends to credit the difference between $7 million and $9 million to commercial (i.e., non-residential) customers, and to credit any refund amount in excess of $9 million to both residential and commercial customers". I would like to clarify at this time that the $2 million figure was an estimated amount referenced in the Company' s petition to utilize a portion of the refund for low income customers. Equitable is unable to determine at this time whether the C & I refund amount will be more or less than $2 million.

Q. IS EQUITABLE PROPOSING A PARTICULAR METHOD FOR DETERMINING THE SHARE OF THE REFUND FOR C & I CUSTOMERS?

A. No. The Company can calculate the proportional share of the refund applicable to C & I customers using a few different methods. The Company is indifferent to the method used, or the exact amount credited to C & I customers, since any remaining amount will be credited generally to PGC gas costs. The Company will abide by any method determined by this Commission.

Q. HOW DOES MR. KALCIC BELIEVE THE REFUND AMOUNT WILL BE CREDITED TO C & I CUSTOMERS?

A. Mr. Kalcic believes that the amount will be credited to C & I customers through a $0.495 reduction in the PGC rate which they pay, in effect creating a different PGC rate for the C & I customers that would be lower than the PGC rate for residential customers.

Q. DOES THE COMPANY INTEND TO FOLLOW THIS METHODOLOGY?

A. No. The Company does not intend to create two different PGC rates.

Q. HOW DOES THE COMPANY INTEND TO CREDIT THE AMOUNT TO C & I CUSTOMERS?

A. The Company intends to provide a one-time bill credit to each C & I customer that paid demand costs. The total credit for the C & I customers will be divided by the annual throughput of the C & I customers identified to determine a unit rate. The unit rate will then be multiplied by the throughput for each of these customers to determine the individual credit to be applied. The one-time bill credit will completely refund the portion due the C & I customers while alleviating the confusion of two separate PGC rates.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes, it does.

ORIGINAL

Equitable Statement No. 2
Docket No. R-00061295
Witness: Jeffrey S. Nehr

JUN 1 6 2006

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PA PUBLIC UTILITY COMMISSION
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EQUITABLE GAS COMPANY

Prepared Direct Testimony of
Jeffrey S. Nehr
(Prepared April 2006)

PREPARED DIRECT TESTIMONY OF JEFFREY S. NEHR

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Jeffrey S. Nehr. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company ("Equitable" or "Company"), a division of Equitable Resources, Inc., as Manager, Gas Supply.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE IN THE GAS INDUSTRY.

A. I graduated from The Pennsylvania State University in 1985 with a Bachelor of Science degree in Petroleum and Natural Gas Engineering. I began my utility career with Peoples Natural Gas in 1988 as a Systems Analyst located in Pittsburgh. After 3 years, I was promoted to Senior Systems Analyst performing project management responsibilities for the Engineering Department. In 1993, I joined the Gas Supply Department as Transmission and Gathering Facilities Engineer. In that capacity, I coordinated new commercial and industrial load additions, pipeline extensions, and new interconnects with interstate pipelines. After 2 years, I was promoted to Gas Supply Planning and Facility Specialist. In that capacity, I performed Supply Planning & Modeling for winter peak day design. I also prepared the design of capacity allocation for the Customer Choice Programs on the Peoples Natural Gas and Hope Gas distribution systems. In 1997, Consolidated Natural Gas Company, the parent company of Peoples Natural Gas, consolidated that function across all of the local distribution companies and I was promoted to Senior Gas Supply Planning Analyst. Shortly thereafter, I joined CNG Energy Services as an LDC Pool Manager. In that capacity, I coordinated the gas supply purchases, planning, and operations for the East Ohio Large Commercial and Energy Choice Pools. Between 1998 and 2000, I held the positions of Senior Energy Aggregation Specialist with DTE-CoEnergy, LLC and Senior Energy Specialist with Green Mountain.Com. My responsibilities were to create and manage natural gas choice offerings in Pennsylvania and New Jersey. In 2000, I left Green Mountain.Com to join Equitable as Market Planner. In that capacity, I was responsible for the preparation, management, and implementation of the Company's Commercial Business Plan. In 2002, I was promoted to Load Research and Planning Coordinator with responsibilities for forecasting demand on Equitable's distribution systems. I also helped manage the interstate supply, direct feed supply and storage to meet the forecasted demand. In 2004, I was promoted to Manager, Gas Supply.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. My primary responsibility involves load forecasting. In addition, I am responsible for Appalachian supply purchases and help manage interstate supply and storage to meet the forecasted demand.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes. I provided direct testimony before this Pennsylvania Public Utility Commission in Equitable's 2004 section 1307(f) proceeding at Docket No. R-00049154 and Equitable's 2005 section 1307(f) proceeding at Docket No. R-00050272.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the Company's design day analysis and discuss the proposed changes to the capacity assignment provisions of the Company's Customer Choice Program.

III. Design Day Analysis

Q. WOULD YOU PLEASE DESCRIBE A DESIGN DAY?

A. A design day is the maximum projected load placed on the system for one day during the course of one year. The design day will occur on the coldest day where lowest temperatures augmented with wind speed generate the greatest heating demand. Natural gas distribution companies utilize the design day to determine the necessary capacity, storage and gas purchase requirements to meet that demand. Planning for the design day involves identifying the design day criteria and the demand an LDC's customers are likely to place upon it during extreme weather conditions and analyzing the LDC's ability to meet that demand.

Q. WHAT IS THE DIFFERENCE BETWEEN A DESIGN DAY AND A PEAK DAY?

A. The design day is normally much colder than the peak day. Design days do not occur every year. An LDC must operate its distribution system to assure delivery of gas in adequate volumes at required pressures under all circumstances. Therefore, design days represent the extreme conditions that an LDC must be prepared to meet. On the other hand, the peak day is simply the highest gas sendout experienced during a 24-hour period during the course of a year.

Q. WHAT CRITERIA DOES EQUITABLE USE FOR DESIGN DAY PLANNING?

A. Equitable's design day criteria consists of the following factors:

(a.) a mean temperature of –10 F, which represents 75 heating degree days ("HDD");

(b.) an average wind speed of 15.8 mph; and

(c.) a winter weekday during January.

Q. WHY ARE THESE FACTORS UTILIZED IN DESIGN DAY PLANNING?

A. While many factors affect gas usage, some are more significant than others. Across the Company's service territory, gas is predominantly used for heating purposes. The most significant factor determining heat usage is temperature. Another important factor is wind. Buildings lose more heat on a windy day than they do on a calm day. The day of the week is also important as many industrial customers and some commercial customers shut down over weekends. The Company has consistently utilized these criteria in its design day analyses and continues to believe that they are appropriate.

Q. WERE THERE ANY CHANGES IN THE DESIGN DAY METHODOLOGY UTILIZED BY THE COMPANY FOR ITS UPDATED 2006 STUDY COMPARED TO THE METHODOLOGY USED IN THE LAST STUDY TO DETERMINE THE DESIGN DAY REQUIREMENTS?

A. All of the input parameters that were used in the last study were again used in the 2006 updated sendout model. Specifically, these input parameters are related to the three criteria discussed earlier. The Company did, however, have a change with respect to the weather data.

Q. PLEASE DESCRIBE THIS WEATHER DATA CHANGE IN MORE DETAIL.

A. During the 2000 design day study, the Company included weather data from the Allegheny County Airport along with data from the Greater Pittsburgh International Airport. The Allegheny County Airport is located southeast of the City of Pittsburgh and is more representative of temperatures experienced within the Company's service territory. On the other hand, the Greater Pittsburgh International Airport is located on the fringe of Equitable's service territory. In the current 2006 design day analysis, the Company is also including data from the Carnegie Science Center in addition to the data from the Allegheny County Airport and the Greater Pittsburgh International Airport. The Carnegie Science Center is located on the North Side, within the City of Pittsburgh, and is most representative of the weather experienced within the Company's service territory.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE COMPANY'S 2006 DESIGN DAY REQUIREMENTS STUDY?

A. The Company has utilized the months of January and February in its design day study. These months are used because they typically have the highest number of heating degree days as well as the highest throughput. Also, the annual peak day typically occurs in these months.

The Company performed multiple regression analyses under two scenarios using the daily sendout from different time periods. The Company analyzed these time periods to search for trends and biases. Scenario #1 was based upon the time period January 2003 through February 2003. The total system design day sendout utilizing the data points for these periods was 621,236 dth (see Equitable Exhibit JSN-1). Scenario #2 was based upon the time period January 2005 through February 2005. The total system design day sendout utilizing the data points for this period was 637,308 dth (see Equitable Exhibit JSN-2).

Q. WHY DID THE COMPANY NOT INCLUDE DATA FROM THE 2004 PERIOD?

A. During January 2004, Equitable implemented a new billing system designed to meet the requirements of its tariff and transportation customers. This new system created significant operational challenges to the users and developers. The transition period from the old billing system to the new billing system occurred primarily during the months of January, February, and March 2004. There were problems with the integrity of the measurement data during this period. As a result, the Company did not include data from the 2004 period in its recent design day analysis.

Q. WHAT TIME PERIOD DOES THE COMPANY BELIEVE IS MOST RELEVANT AND PROVIDES THE MOST ACCURATE RESULTS?

A. The Company would place greater reliance on Scenario #2 (2005) than on Scenario #1 (2003) for several reasons. First of all, Scenario #2 utilizes the most recent data available. During last year's 1307(f) proceeding, OCA Witness Mierzwa recommended, in his Direct Testimony, that Equitable use more recent data to capture changes in transportation customers and standby service requirements when conducting a design day analysis. Secondly, the R-Square for the 2005 model, 0.9434, is better than the R-Square for the 2003 model, 0.9302. R-Square is the proportion of variation in the dependent variable explained by the regression model. Smaller R-Square values indicate that the model does not fit the data well.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE COMPANY'S DESIGN DAY ANALYSIS?

A. The primary components included in Equitable's design day analysis are: projected system sendout or the projected total system requirements; projected transportation requirements; projected standby requirements; and projected balancing requirements.

Q. WHAT IS THE SIGNIFICANCE OF THE PROJECTED TOTAL SYSTEM REQUIREMENTS AND HOW IS IT CALCULATED?

A. The projected total system requirements represents Equitable's maximum load or sendout, on a design day, for its PGC sales and transportation customers.

In order to compute the maximum load, the Company identified the daily volumetric data at each delivery point into its distribution system. These delivery points include receipt points on Equitrans as well as Appalachian direct feed meters. The volumes delivered through Equitrans are provided daily. However, the volumes delivered through Appalachian direct feed meters are only provided monthly. The Company converted these monthly volumes into daily volumes and added them to the Equitrans deliveries to arrive at total daily delivered volumes. These total daily delivered volumes were then regressed against corresponding daily temperatures and wind speeds in order to determine the appropriate baseload requirements and heating requirements. These baseload requirements and heating requirements were then extrapolated using Equitable's design day criteria, i.e., 75 heating degree days and a wind speed of 15.8 mph, to develop the projected total system requirements. The projected total system requirements utilizing 2003 and 2005 data are identified as Exhibits JSN-1 and JSN-2, respectively.

Q. WHAT HAS CHANGED TO CAUSE THE TOTAL SYSTEM REQUIREMENT TO INCREASE FROM 588,839 DTH IN 2001 IN THE LAST DESIGN DAY STUDY TO 637,308 DTH IN 2006?

A. The total system requirement has changed since 2001 due to additional usage by the Company's largest industrial transportation customer. During the last study period, this customer used approximately 386,000 dth in January 2001, and approximately 277,000 dth in February 2001. For the recent test period, the customer consumed approximately 1,269,083 dth for January 2005 and 838,008 dth for February 2005.

Q. WHAT IMPACT DOES THIS HAVE TO THE PROJECTED FIRM REQUIREMENTS ON EQUITRANS?

A. As a transportation customer this increased usage has no impact on the projected firm requirements on Equitrans. This customer, as Equitable witness Rafferty's testimony will explain, is served directly from a former Carnegie high pressure transmission facility. Furthermore, this customer is balanced daily and is required to match its daily supply with its daily consumption. In other words, the projected total system requirements increased, but, in offsetting fashion, so did the projected transportation requirements.

Q. WHAT IS THE SIGNIFICANCE OF THE PROJECTED TRANSPORTATION REQUIREMENTS AND HOW WERE THEY CALCULATED?

A. The projected transportation requirements represent the gas supply that marketers are responsible for delivering to Equitable on behalf of the customers they serve. Unless these customers pay the firm standby charge, Equitable is not obligated to provide service if their supplier fails to deliver on a design day.

The Company performed a regression analysis of all transportation customers, by class, for January 2005. This month was chosen because it is the peak heating month during the test period and accordingly would generate the greatest transportation requirements. Baseload values and heat factor values were calculated for each customer class. Projected transportation requirements were then calculated for those transportation customers in existence during January 2005. The results of this analysis and the corresponding projected transportation requirements are presented in Equitable Exhibit JSN-3.

Q. WHAT IS STANDBY AND HOW ARE THE PROJECTED TRANSPORTATION STANDBY REQUIREMENTS CALCULATED?

A. Firm standby service provides customers a level of service that, in most cases, is not interruptible. The Company's Tariff provides that:

> "For a customer who does not receive Firm Standby Service, daily consumption in excess of daily deliveries on customer's behalf, in excess of customer's Maximum Daily Firm Requirement (MDFR) or in excess of a customer's Maximum Daily Quantity (MDQ) is interruptible." Tariff Sheet No. 78.

In order to determine the projected transportation standby requirements, the Company identified which transportation customers during January 2005 subscribed to firm standby. The projected standby requirements were then calculated for those transportation customers paying the firm standby charges using the baseload values and heat values that were calculated for each customer class. This is the same methodology that was used previously to calculate the projected transportation requirements. The results of this analysis and the corresponding projected standby requirements are presented in Equitable Exhibit JSN-4.

Q. WHAT IS THE SIGNIFICANCE OF THE PROJECTED TRANSPORTATION BALANCING REQUIREMENTS AND HOW IS IT CALCULATED?

A. The transportation balancing requirements represent the difference between the gas supply that is delivered on behalf of the customer and the amount of gas that is actually consumed by the customer. Transportation customers pay for this balancing service through the Company's balancing charge.

The Company compared the daily nominations of all transportation customers with their expected daily usage based on the actual heating degree days that occurred during the month of January, 2005. The difference in nominated supply on that day versus the projected usage on that day represents approximately a 20% shortfall in supply. Consistent with this behavior, the Company projected balancing requirements expressed as this percentage of the total projected transportation requirements. The results of this analysis are presented in Equitable Exhibit JSN-5.

Q. WHY IS IT IMPORTANT TO INCLUDE PROJECTED BALANCING REQUIREMENTS IN THE DESIGN DAY ANALYSIS?

A. Transportation customers use this balancing service daily. These customers do not acknowledge changing weather conditions. Transportation customers typically baseload their expected usage for the month. They may make an attempt during the last several days of the month to adjust their nominations to their consumption. Usually, this is done only to avoid imbalance penalties. One can reasonably assume that this same behavior will occur on a design day.

Q. PLEASE SUMMARIZE THE RESULTS AS DOCUMENTED IN EQUITABLE EXHIBIT NO. JSN-6?

A. The beginning number (Line 1) represents the projected total system requirements expected to occur under design day conditions, which equals 637,308 dth. There is an expected level of throughput, however, that is attributable to Equitable's standby and non-standby transportation customers. As I mentioned previously, the Company's PGC customers are not responsible for the capacity or the gas supplies serving these transportation customers. Therefore, we must subtract the expected level of design day throughput (Line 2) for this group from the projected total system requirements (Line 1). This results in the projected PGC sales requirements (Line 3). Next, the Company added back both the projected standby requirements (Line 4) and the projected balancing requirements for transportation customers (Line 5). The result is a total of 520,294 dth of projected design day firm requirements (Line 6). Finally, the Company subtracted an estimated level of direct-feed Appalachian supply purchased on behalf of PGC customers (Line 7). The final result indicates 505,294 dth of Equitrans capacity is necessary to meet the Company's design day firm requirements (Line 8).

Q. HOW WAS THE PROJECTED APPALACHIAN DIRECT FEED SUPPLY CALCULATED?

A. Since the last design day study, the Company has significantly enhanced its local Appalachian production purchases through the implementation of the Northern Asset Optimization Program ("NAOP"). Transportation customers, as well as PGC customers, have benefited from access to additional direct-feed Appalachian supplies. This direct-feed supply does not require capacity on Equitrans to effectuate delivery to the Company's city-gate. As a result, the Company has reflected a decrease in the design day requirements (Line 7).

Q. DOES EQUITABLE ANTICIPATE ENTERING INTO CONTRACTS WITH EQUITRANS FOR 505,294 DTH OF FIRM CAPACITY AS INDICATED BY LINE 8 ON EQUITABLE EXHIBIT JSN-6?

A. No. Equitable has made adjustments to projected standby requirements and projected balancing requirements that reduce the indicated firm capacity below 505,294 dth.

Q. HOW DID EQUITABLE DEVELOP THE FINAL STANDBY REQUIREMENTS IN ITS DESIGN DAY ANALYSIS IN THIS PROCEEDING?

A. Equitable developed the final standby requirements based on the standby credits collected from transportation customers. Equitable's 2005 Standby Credits were $2,875,888. The average unit cost of capacity is $118.99/dth. The standby credits divided by the unit cost results in standby requirements equal to 24,168 dth ($2,875,888 / $118.99). To determine the final standby requirement, the Company is reducing the projected standby requirements from 36,796 dth (line 4 of Equitable Exhibit JSN-6) to 24,168 dth.

Q. DID EQUITABLE DEVELOP THE FINAL BALANCING REQUIREMENTS IN A SIMILAR MANNER?

A. Yes, it did. Equitable's 2005 transportation balancing credits were $1,249,935. Total projected No-Notice costs are $7,484,137. Thus, transportation customers pay for approximately 16.7% of the total projected No-Notice costs ($1,249,935 / $7,484,137). Equitable is projecting total company No-Notice service requirements equal to 79,545 dth/day. The projected transportation balancing requirements based on a 16.7% allocation is 13,285 dth (0.167 x 79,545).

Q. CAN YOU SUMMARIZE THE ADJUSTMENTS YOU HAVE DESCRIBED TO THE PROJECTED STANDBY REQUIREMENTS AND THE PROJECTED BALANCING REQUIREMENTS AND THE EFFECT THEY HAVE ON THE PROJECTED FIRM REQUIREMENTS ON EQUITRANS?

A. Yes. Equitable's projected standby requirements decreased from 36,796 dth to 24,168 dth resulting in a 34% reduction in requirements. Equitable's projected balancing requirements decreased from 40,068 dth to 13,285 dth resulting in a 67% reduction in requirements. The projected firm requirements on Equitrans decreased from 505,294 dth to 465,883 dth. See Exhibit JSN-7 for the derivation of projected firm requirements on Equitrans.

IV. Capacity Assignment For Customer Choice Program

Q. WOULD YOU PLEASE DESCRIBE THE CAPACITY ASSIGNMENT PROVISIONS OF EQUITABLE'S CUSTOMER CHOICE PROGRAM?

A. Equitable subscribes to firm transportation and firm storage capacity that is sufficient to meet the design day requirements for all of the customers that require firm service. Some customers elect to have an alternate supplier provide their commodity service in lieu of Equitable. These customers can change suppliers monthly or yearly depending upon the supply contract offering. If a customer chooses not to renew their contract with the alternate supplier, Equitable becomes the supplier of last resort, by default, and extends commodity service to that customer. Because of these dynamics, Equitable must contract for sufficient pipeline and storage capacity to serve all firm service customers.

If a customer chooses an alternate supplier, the pipeline and storage capacity Equitable originally reserved for that customer is released to the alternate supplier at the maximum tariff rates. It is the responsibility of the alternate supplier to recover those pipeline charges through a commodity contract with the customer.

Q. WHAT ARE THE CURRENT CAPACITY ASSIGNMENT ALLOCATIONS?

A. Equitable generates, on a monthly basis, a design maximum daily quantity or MDQ for all customers that are released to the alternate supplier. Next, Equitable will release approximately 30% interstate pipeline capacity and 70% interstate storage capacity to support 100% recovery of the aggregate customer design day requirements. The interstate pipeline capacity that is released consists of Texas Eastern Transmission and Equitrans. The interstate storage capacity consists entirely of Equitrans and is divided among the various storage services as follows: 40% Rate Schedule 115-SS; 25% Rate Schedule 10-SS; 27% Rate Schedule 30-SS;

and 8% Rate Schedule 60-SS. See Exhibit JSN-8 for an example of the current capacity assignment methodology.

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO THE CAPACITY ASSIGNMENT PROVISIONS SINCE THE DESIGN DAY REQUIREMENTS AND PIPELINE ENTITLEMENTS HAVE CHANGED?

A. Equitable is proposing to continue to release approximately 30% of the interstate pipeline capacity and approximately 70% of the interstate storage capacity, consistent with its current procedures. However, the Company is proposing a change to the capacity release provisions regarding the interstate storage services. Please refer to the Direct Testimony of Equitable Witness Rafferty for a discussion of the new contractual storage services, effective April 1, 2006. The new Equitrans storage capacity assignment beginning April 1, 2006 will be: 27% Rate Schedule 115-SS and 73% Rate Schedule 60-SS. See Exhibit JSN-9 for an example of the proposed capacity assignment methodology.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

SUMMARY OUTPUT

MULTIPLE REGRESSION ANALYSIS
EGC & CARNEGIE DAILY SENDOUT
HDD=75
MEAN WIND 15.8 mph

Equitable Exhibit JSN-1

PROJECTED SENDOUT = **621,236 DTH**

PERIOD: JANUARY 2003 THRU FEBRUARY 2003

Regression Statistics	
Multiple R	0.9645
R Square	0.9302
Adjusted R Square	0.9277
Standard Error	17424
Observations	59

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	226487546358	113243773179	373	0
Residual	56	17001491763	303598067	0	0
Total	58	243489038122	0	0	0

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	28120.0	12096.9	2.3	0.0	3887.1	52352.9	3887.1	52352.9
X Variable 1	7615.1	294.8	25.8	0.0	7024.5	8205.8	7024.5	8205.8
X Variable 2	1391.4	713.4	2.0	0.1	-37.7	2820.4	-37.7	2820.4

SUMMARY OUTPUT

MULTIPLE REGRESSION ANALYSIS
EGC & CARNEGIE DAILY SENDOUT
HDD=75
MEAN WIND 15.8 mph

Equitable Exhibit JSN-2

Regression Statistics	
Multiple R	0.9713
R Square	0.9434
Adjusted R Square	0.9413
Standard Error	23581
Observations	59

PROJECTED SENDOUT = **637,308 DTH**

PERIOD: JANUARY 2005 THRU FEBRUARY 2005

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	518742167716	259371083858	466	0
Residual	56	31138933765	556052389	0	0
Total	58	549881101481	0	0	0

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	38539.8	11254.8	3.4	0.0	15993.8	61085.9	15993.8	61085.9
X Variable 1	8032.8	265.7	30.2	0.0	7500.6	8565.0	7500.6	8565.0
X Variable 2	-233.7	1101.0	-0.2	0.8	-2439.3	1971.8	-2439.3	1971.8

Equitable Exhibit JSN-3

Equitable Gas Company

Projected Design Peak Day
Transportation Requirements

Month/Year	Total Number of Customers	Total Throughput (Mcf)	Baseload per customer (July+August)	Baseload per customer per day (Mcf)	Actual HDD (Calendar)	Heat Factor	Heat Factor per customer	Projected Demand (Mcf) (@ 75 HDD)	Retainage (5%)	Projected Demand (Dth) (@ 75 HDD)
COMMERCIAL:										
January-2005	3,396	1,621,734	140.8773	4.5444	1,058	1,080.6	0.3182	96,481	5,078	107,652
July-2005	3,355	347,601								
August-2005	3,362	598,932								
[redacted]										
INDUSTRIAL:										
January-2005	136	1,318,351	3079.1860	99.3286	1,058	850.3	6.2520	77,279	4,067	86,227
July-2005	140	448,682								
August-2005	139	410,536								
[redacted]										
								173,759		193,879

Equitable Exhibit JSN-4

Equitable Gas Company

Projected Design Peak Day
Standby Requirements

Month/Year	Total Number of Customers	Total Throughput (Mcf)	Baseload per customer (July+August)	Baseload per customer per day (Mcf)	Actual HDD (Calendar)	Heat Factor	Heat Factor per customer	Projected Demand (Mcf) (@ 75 HDD)	Retainage (5%)	Projected Demand (Dth) (@ 75 HDD)
COMMERCIAL:										
January-2005	2213	459659.1	25.5208	0.8233	1,058	381.1	0.1722	30,403	1,600	33,923
July-2005	2213	54419.9								
August-2005	2213	58535.3								
[redacted]										
INDUSTRIAL:										
January-2005	78	39616.1	77.4737	2.4992	1,058	31.7	0.4068	2,575	136	2,873
July-2005	78	5915.6								
August-2005	78	6170.3								
[redacted]										
						Total Projected Demand		32,978		36,796

Equitable Exhibit JSN-5

DAILY IMBALANCE ESTIMATE FOR TRANSPORTATION CUSTOMERS

DAY	HDD	WIND SPEED	EGC NOMINATIONS	CARNEGIE NOMINATIONS	WELL GAS	TRANSPORT NOMINATIONS	PROJECTED BURN	ESTIMATED VARIANCE	VARIANCE (%) OF NOMINATIONS
01/01/2005	17	5	42025	32591	9509	84125	68919	15206	22%
01/02/2005	9	8	40964	32591	7035	80590	51683	28907	56%
01/03/2005	15	8	40870	32591	7611	81072	64610	16462	25%
01/04/2005	23	5	40938	32591	12569	86098	81846	4252	5%
01/05/2005	23	7	40964	32591	16385	89940	81846	8094	10%
01/06/2005	25	12	40087	32592	17469	90148	86155	3993	5%
01/07/2005	28	5	40087	43763	17816	101666	92618	9048	10%
01/08/2005	29	7	40087	47142	17814	105043	94773	10271	11%
01/09/2005	25	6	40087	47142	16460	103689	86155	17534	20%
01/10/2005	28	7	40087	47142	17664	104893	92618	12275	13%
01/11/2005	18	5	40087	39398	14182	93667	71073	22594	32%
01/12/2005	5	8	40087	52493	7000	99580	43065	56515	131%
01/13/2005	13	13	40783	42292	8988	92063	60301	31762	53%
01/14/2005	39	9	40087	39837	21255	101179	116318	15139	13%
01/15/2005	39	4	40744	37145	22414	100303	116318	16014	14%
01/16/2005	48	11	40951	37145	27508	105604	135708	30104	22%
01/17/2005	57	12	40445	37145	34584	112174	155098	42925	28%
01/18/2005	51	6	40403	37145	32408	109956	142171	32215	23%
01/19/2005	40	11	40051	32592	27171	99814	118472	18658	16%
01/20/2005	47	8	41044	42292	28431	111767	133553	21786	16%
01/21/2005	49	5	38445	47917	29845	116207	137862	21655	16%
01/22/2005	48	13	37426	51540	30921	119887	135708	15821	12%
01/23/2005	56	7	36345	51540	34281	122166	152944	30778	20%
01/24/2005	48	8	37426	49084	31264	117774	135708	17934	13%
01/25/2005	32	6	37426	56165	22907	116498	101236	15262	15%
01/26/2005	42	11	38526	56535	27282	122343	122781	438	0%
01/27/2005	52	6	37445	45323	32386	115154	144326	29171	20%
01/28/2005	45	5	37445	49728	27809	114982	129244	14263	11%
01/29/2005	35	3	39526	47838	23226	110590	107700	2891	3%
01/30/2005	35	5	40241	47838	22107	110186	107700	2487	2%
01/31/2005	37	2	39480	48487	28330	116297	112009	4289	4%
Average	34	7.2	39697	42910	21762	104370	105823	18346	20.67%

Equitable Gas Company

Derivation of Firm Design Peak Day Requirements

		Source
(1) Projected Total System Requirements:	637,308 Dth	Exhibit JSN-2
(2) Projected Transportation Requirements:	(193,879) Dth	Exhibit JSN-3
(3) Projected PGC Sales Requirements:	443,430 Dth	{ (1) - (2) }
(4) Projected Standby Requirements:	36,796 Dth	Exhibit JSN-4
(5) Projected Balancing Requirements:	40,068 Dth	Exhibit JSN-5
(6) Projected Design Peak Day Firm Requirements:	520,294 Dth	{ (3) + (4) + (5) }
(7) Projected Appalachian Direct Feed:	(15,000) Dth	
(8) Projected Firm Requirements on Equitrans:	505,294 Dth	{ (6) - (7) }

Equitable Gas Company

Derivation of Firm Design Peak Day Requirements - Revised

		Source
(1) Projected Total System Requirements:	637,308 Dth	Exhibit JSN-2
(2) Projected Transportation Requirements:	(193,879) Dth	Exhibit JSN-3
(3) Projected PGC Sales Requirements:	443,430 Dth	{ (1) - (2) }
(4) Projected Standby Requirements:	24,168 Dth	
(5) Projected Balancing Requirements:	13,285 Dth	
(6) Projected Design Peak Day Firm Requirements:	480,883 Dth	{ (3) + (4) + (5) }
(7) Projected Appalachian Direct Feed:	(15,000) Dth	
(8) Projected Firm Requirements on Equitrans:	465,883 Dth	{ (6) - (7) }

Equitable Gas Company

Current Derivation of Capacity Allocation

(1) Projected Total Customers MDQ		20,000	Dth/Day	
(2) Pipeline Capacity Allocation		10,000	Dth/Day	
(2a) Texas Eastern Pipeline Capacity		6,300	Dth/Day	
(2b) Tennessee Pipeline Capacity		3,700	Dth/Day	
(3) Revised Pipeline Allocation, Less Tennessee		6,300	Dth/Day	31.5%
(4) Storage Capacity Allocation		10,000	Dth/Day	
(4a) EQT Storage 115ss	17.60%	1,760	Dth/Day	12.8%
(4b) EQT Storage 10ss	34.70%	3,470	Dth/Day	25.3%
(4c) EQT Storage 30ss	37.00%	3,700	Dth/Day	27.0%
(4d) EQT Storage 60ss	10.70%	1,070	Dth/Day	7.8%
(4e) EQT Storage 115ss, Replace Tennessee		3,700	Dth/Day	27.1%
(5) Revised Storage Capacity Allocation		13,700	Dth/Day	68.5%

* Pipeline and Storage Capacity must be grossed up by 3.77% Equitrans Fuel

** All Storage must have corresponding pipeline capacity grossed up by 2.3% *Equitrans Storage Fuel*

Equitable Exhibit JSN-9

Equitable Gas Company

Proposed 2006 Derivation of Capacity Allocation

(1) Projected Total Customers MDQ		20,000	Dth/Day	
(2) Pipeline Capacity Allocation		10,000	Dth/Day	
(2a) Texas Eastern Pipeline Capacity		6,300	Dth/Day	
(2b) Tennessee Pipeline Capacity		3,700	Dth/Day	
(3) Revised Pipeline Allocation, Less Tennessee		6,300	Dth/Day	31.5%
(4) Storage Capacity Allocation		10,000	Dth/Day	
(4a) EQT Storage 115ss	26.95%	2,695	Dth/Day	12.8%
(4d) EQT Storage 60ss	73.05%	7,305	Dth/Day	7.8%
(4e) EQT Storage 115ss, Replace Tennessee		3,700	Dth/Day	27.1%
(5) Revised Storage Capacity Allocation		13,700	Dth/Day	68.5%

* Pipeline and Storage Capacity must be grossed up by 3.77% Equitrans Fuel

** All Storage must have corresponding pipeline capacity grossed up by 2.3% Equitrans Storage Fuel

ORIGINAL

Equitable Statement No. 2-R
Docket No. R-00061295
Witness: Jeffrey S. Nehr
JUN 16 2006

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Jeffrey S. Nehr

(Prepared in June 2006)

PREPARED REBUTTAL TESTIMONY OF JEFFREY S. NEHR

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Jeffrey S. Nehr. My business address is 225 North Shore Drive, Pittsburgh, PA 15212.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company, a division of Equitable Resources, Inc., as Manager, Gas Supply.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted direct testimony that has been marked as Equitable Statement No. 2.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony I will respond to the direct testimony of Office of Consumer Advocate ("OCA") witness Jerome D. Mierzwa. Specifically, I will respond to issues raised concerning the Company's proposed design day analysis.

III. Design Day Analysis

Q. PLEASE SUMMARIZE THE POSITIONS OF THE OCA REGARDING THE COMPANY' S PROPOSED DESIGN DAY ANALYSIS.

A. The OCA has filed testimony proposing changes to the Company' s design day analysis and subsequent capacity portfolio. OCA witness Mierzwa recommends using only the 2006 data for performing the design day analysis. Mr. Mierzwa selected 2006 data based on a belief that significant demand destruction occurred as a result of high gas prices. The OCA anticipates that " natural gas prices will remain high for the foreseeable future". Based on the OCA testimony, the Company' s design day analysis is overstated by 30,000 Dth. Mr. Mierzwa is recommending that the Company aggressively pursue realigning its capacity portfolio by " renegotiating current contracts, releasing excess capacity, and examining whether its proposed merger with Dominion Peoples will provide opportunities to shed capacity".

Q. DOES MR. MIERZWA QUANTIFY THE IMPACT OF THE CHANGES HE RECOMMENDED?

A. No. Due to the uncertainties in Equitable' s ability to realign its capacity portfolio as a result of the Dominion Peoples acquisition, Mr. Mierzwa does not recommend adjustments to purchased gas costs at this time.

Q. DOES MR. MIERZWA QUANTIFY THE IMPACT OF HIGH GAS PRICES ON CUSTOMER DEMAND?

A. No. Mr. Mierzwa does not bother to offer facts or comparative analysis to support his theory that only high gas prices reduced customer demand.

Q. DOES MR. MIERZWA QUANTIFY THE FORECAST FOR HIGH NATURAL GAS PRICES?

A. No. Again, Mr. Mierzwa does not offer facts, comparative analysis or references to industry experts that would substantiate his theory that natural gas prices will remain high for the foreseeable future.

Q. WHY DID EQUITABLE NOT INCLUDE 2006 IN ITS DESIGN DAY ANALYSIS?

A. Equitable prepared its design day analysis during January 2006. A portion of the January 2006 data and all of the February 2006 data was not available at the time the study was performed. Equitable selected the period for analysis based on the availability of data at the time the study was performed.

Q. DOES EQUITABLE BELIEVE ONLY THE 2006 DATA SHOULD BE USED TO PERFORM A DESIGN DAY ANALYSIS?

A. No. Equitable would not have used the January 2006 data for design day analysis due to excessively warm temperatures. The Company' s design day analysis was performed to predict demand on the system under extremely cold temperatures where the system limits are tested. Instead, the OCA chose January 2006 which ranks as the seventh warmest out of the past 135 years and is 26% warmer than the 100 year normal January. Design days never occur during warmer than normal periods. January 2006 also lacked significant snowfall or prolonged snow cover. One can draw the conclusion that ground temperatures were also warmer than normal due to diminished snow accumulation.

Q. WHAT SIGNIFICANCE DOES AMBIENT TEMPERATURE, SNOWFALL, AND GROUND TEMPERATURES HAVE ON CUSTOMER DEMAND?

A. The single most important factor in design day analysis is ambient temperature. Ninety-four percent of Equitables design day is due to ambient temperature impact. Snowfall and ground temperature also impact design day analysis but are seldom used in studies due to lack of quantifiable weather data. Nevertheless, these factors, under warmer than normal conditions, contribute to reduced customer demand. Most residential homes in southwestern Pennsylvania have basements, where a portion of the home is below ground. If the ground temperature is cold, it takes more energy to heat the home. Conversely, if the ground temperature is warm, it takes less energy to heat the home. Equitable believes that the extremely warm weather that occurred in January 2006 contributed to reduced customer demand, not a high gas price environment.

Q. DOES THE COMPANY AGREE WITH MR. MIERZWA' S ANALYSIS PRESENTED IN SCHEDULE JDM-2?

A. No. Mr. Mierzwa presented an analysis in Schedule JDM-2 that uses 2006 weather data in conjunction with Equitable' s design day regression factors. Next, he compares these forecasted results to the actual demand experienced during that period. Based on his analysis, he believes Equitable' s regression model was overstated by 11.2%. The Company believes it is not appropriate to use a different set of variables in an existing model and expect the results to be conclusive. This is precisely what Mr. Mierzwa has done.

Q. HAS THE COMPANY PERFORMED A DESIGN DAY STUDY UTILIZING BOTH THE 2005 AND 2006 HISTORICAL DATA?

A. Yes. The Company has utilized weather data from January and February 2005 in conjunction with January and February 2006 to update its design day study. The Company completed a regression analysis using the data from these four months. The regression results were analyzed for trends and biases to determine what factors contributed to the accuracy of the regression model. Based on this analysis, the Company determined that wind speed did not make a significant contribution to total design day sendout. Therefore, wind speed was excluded from this updated design day study. The updated design day sendout utilizing the weather data from 2005 and 2006 indicates the projected firm requirements are 617,317 dth. Please see Equitable Schedule JSN-1-R for the results of this updated design day study.

Q. HAS THE COMPANY UPDATED THE PROJECTED TRANSPORTATION

DESIGN DAY REQUIREMENTS FOR THE 2005 AND 2006 HISTORIC DATA?

A. Yes. The Company performed a regression analysis of all transportation customers, by class, for January 2005 and January 2006. Baseload values and heat factor values were calculated for each customer class. Projected transportation requirements were then calculated for those transportation customers in existence during January 2005 and January 2006. The results of this analysis and the corresponding projected transportation requirements are presented in Equitable Schedule JSN-2-R.

Q. PLEASE SUMMARIZE THE RESULTS AS DOCUMENTED IN EQUITABLE SCHEDULE NO. JSN-3-R?

A. The beginning number (Line 1) represents the projected total system requirements expected to occur under design day conditions, which equals 617,317 dth. There is an expected level of throughput, however, that is attributable to Equitable's standby and non-standby transportation customers. The Company's PGC customers are not responsible for the capacity or the gas supplies serving these transportation customers. Therefore, we must subtract the expected level of design day throughput (Line 2) for this group from the projected total system requirements (Line 1). This results in the projected PGC sales requirements (Line 3). Next, the Company added back both the projected standby requirements (Line 4) and the projected balancing requirements for transportation customers (Line 5). The result is a total of 473,119 dth of projected design day firm requirements (Line 6). Finally, the Company subtracted an estimated level of direct-feed Appalachian supply purchased on behalf of PGC customers (Line 7). The final result indicates 458,119 dth of Equitrans capacity is necessary to meet the Company's design day firm requirements (Line 8).

Q. WHAT IS THE IMPACT OF UNDERSTATING CUSTOMER DEMAND WHEN DESIGN DAY CONDITIONS OCCUR?

A. When design day weather conditions occur, Equitable is utilizing all of the capacity it reserved with upstream interstate pipelines to transport gas purchased to meet design day demand. In the event design day demand is understated, Equitable would not have sufficient capacity to meet customer demand. Equitable would be forced into the market to secure delivered gas, if available, or secure interruptible capacity to transport gas. Under design day conditions, most interstate pipelines are tested to the limits of their operations. Those interstate pipelines may exercise operational flow orders and eliminate interruptible transport to preserve deliverability to their firm customers. Ultimately, Equitable would be at risk if its transportation capacity is insufficient to meet customer demand.

Q. DOES EQUITABLE AGREE WITH MR. MIERZWA' S CONTENTION THAT HIGH NATURAL GAS PRICES REDUCED CUSTOMER?

A. No. Equitable Gas experienced a much warmer than normal January in 2006, which combined with minimal snowfall, resulted in reduced customer demand. Certainly, there were higher natural gas prices during the 2005-2006 winter heating season. Neither the OCA nor Equitable Gas has factual data to substantiate whether demand was reduced from the mild winter weather or high natural gas prices. In either case, in my opinion, the data generated in 2006 should not be used in design day analysis.

Q. DOES EQUITABLE BELIEVE THAT HIGH NATURAL GAS PRICES WILL EXIST FOR THE FORSEEABLE FUTURE?

A. No. Gas prices have fallen significantly from their recent high and continue to fall. The storage data published by EIA indicates that the country has a supply surplus due to the mild winter and aggressive storage injections. If storage injections continue at their torrid pace, storage inventory will peak at 3.3 Tcf by September 1, 2006. Should this occur, demand for natural gas will likely fall, which should contain the price for natural gas. Keep in mind that there was an unusually active hurricane season during 2005 that impacted the production facilities in the Gulf of Mexico, which contributed, significantly to the rise in natural gas prices. A large portion of the production and gathering infrastructure in the Gulf of Mexico was disrupted before, during, and after the hurricane season. In fact, some of these facilities did not come back on line until after January 2006.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes, it does.

Equitable Gas Company

Derivation of Firm Design Peak Day Requirements - Revised

		Source
(1) Projected Total System Requirements:	617,317 Dth	Exhibit JSN-12
(2) Projected Transportation Requirements:	(181,651) Dth	Exhibit JSN-13
(3) Projected PGC Sales Requirements:	435,666 Dth	{ (1) - (2) }
(4) Projected Standby Requirements:	24,168 Dth	
(5) Projected Balancing Requirements:	13,285 Dth	
(6) Projected Design Peak Day Firm Requirements:	473,119 Dth	{ (3) + (4) + (5) }
(7) Projected Appalachian Direct Feed:	(15,000) Dth	
(8) Projected Firm Requirements on Equitrans:	458,119 Dth	{ (6) - (7) }

ORIGINAL

Equitable Statement No. 3
Docket No. R-00061295
Witness: John M. Quinn

EQUITABLE GAS COMPANY

Prepared Direct Testimony of

John M. Quinn

(Prepared April 2006)

PREPARED DIRECT TESTIMONY OF JOHN M. QUINN

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is John M. Quinn. My business address is 225 North Shore Drive, Pittsburgh, PA 15212-5352.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Equitable Gas Company ("Equitable" or "Company"), a division of Equitable Resources, Inc., as Director of Rates.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF RATES?

A. I am responsible for the development and coordination of rate, tariff, and other regulatory activity for Equitable's distribution operations in Pennsylvania and West Virginia and its farm tap customers in Kentucky.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND?

A. I have been in my current position with Equitable since 2003. Prior to joining Equitable I was employed by NiSource, Inc. or its predecessor companies from 1989 to 2002 in positions of increasing responsibility in several rate and regulatory affairs positions. As the Director of Regulatory Policy and Planning with

NiSource I was responsible for rate, tariff, and regulatory activity in Pennsylvania, Virginia, and Maryland.

From 1984 to 1989 I was employed by the Iowa State Utilities Board's ("ISUB") [1] Bureau of Rate and Safety Evaluation focusing on the regulation of natural gas distribution and interstate pipelines.

I graduated from the University of Northern Iowa with a Bachelor of Arts Degree, majoring in Accounting. I have also earned a Masters Degree in Public Management with a concentration in Finance from Carnegie Mellon University. While with NiSource, I successfully completed their Executive Development Program at The Wharton School at the University of Pennsylvania. I have also attended a variety of seminars and continuing education courses on ratemaking and finance sponsored by various accredited universities and trade associations over the course of my professional career.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION OR ANY OTHER UTILITY COMMISSION?

A. Yes. I have presented testimony and, on occasion, appeared as a witness in 1307(f) proceedings before this Commission including Docket Nos. R-00050272, R-00049154, R-00016179, R-00005110, R-009844307 and R-00973931. I also submitted testimony before this Commission in Docket No. R-00994781, a natural gas restructuring proceeding. In addition, I have presented testimony and appeared

[1] The ISUB is responsible for the regulation of investor owned natural gas, electric, and telephone companies providing retail service in Iowa.

as a witness on a variety of rate and tariff issues in gas cost proceedings and base rate cases before the state utility commissions of West Virginia, Maryland, Ohio, Virginia, and Iowa.

Q. ARE YOU ACTIVE IN ANY NATURAL GAS TRADE ASSOCIATIONS?

A. Yes. I am active in several committees with the Pennsylvania Energy Association and the American Gas Association.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. During Equitable's 2004 and 2005 1307(f) proceedings, the issue of discounting or waiving tariff rates was a contested issue. While a settlement was reached in the 2004 1307(f) proceeding, the issue was fully litigated in the Company's 2005 1307(f) proceeding. As a result, the Commission issued an Order in Docket No. R-00050272 providing guidance on the treatment of discounts and waivers in future 1307(f) proceedings. The Commission's order required that if Equitable exercised its discretion to discount or waive tariff rates in the future the Company must provide a demonstration of the positive benefits to customers as a result of the discounts or waivers. My direct testimony will provide the demonstration requested by the Commission.

Q. WHAT TARIFF PROVISIONS, SUBJECT TO THIS PROCEEDING, DOES EQUITABLE HAVE DISCRETION TO NEGOTIATE?

A. Equitable has tariff authority to negotiate several non-gas cost and gas cost related tariff provisions. However, the subject of this proceeding relates to Equitable's October 1, 2006 projected annual gas cost rate. As such, the requested demonstration will focus on three gas cost related tariff provisions that Equitable has discretion to negotiate: (1) system average fuel retention for transportation customers; (2) the Rider B, Transportation Migration Rider; and (3) balancing charges.

Q. WOULD YOU PLEASE EXPLAIN THE DECISION REACHED BY THE COMMISSION IN DOCKET NO. R-00050272 RELATED TO DISCOUNTING AND WAIVING TARIFF RATES OR RULES?

A. Yes. The Commission's decision in Docket No. R-00050272 reaffirms that one of its principal goals in allowing NGDCs the ability to negotiate or discount tariff rates is to provide a benefit to all customers through retaining delivery service to large volume customers who make a significant contribution to the recovery of an NGDC's cost of providing utility delivery service. However, the Commission also concluded that it was unreasonable to transfer the associated costs of rate discounts to PGC customers if the discount was offered in order to induce a customer to switch its delivery service from another jurisdictional NGDC, or to match an offer made to an existing customer by a competing jurisdictional NGDC in order to retain the load.

Q. DID THE COMMISSION INDICATE THAT THERE ARE EXCEPTIONS WHERE IT WOULD BE REASONABLE FOR PGC CUSTOMERS TO ASBORB THE COSTS OF DISCOUNTED OR WAIVED TARIFF RATES OR RULES?

A. Yes. The Commission has determined that a two pronged test must be administered in order to determine if it is reasonable to require PGC customers to bear the costs of discounted or waived tariff rates. First, the individual customer must fall under at least one of the following circumstances:

1. A customer may obtain service through a direct bypass;
2. A customer receives service through facilities which do not incur the system average retainage percentage;
3. A competitive offer is received from a non-jurisdictional entity;
4. Economic development and job retention issues impact the rate paid by the customer;
5. A customer receives a bona fide competitive offer from an alternative energy source; or
6. Other instances in which a utility has properly exercised its discretion.

Second, the existing customer charges should also recover the marginal cost of delivering gas to ensure a contribution to fixed costs.

Q. CAN YOU EXPLAIN WHAT IS MEANT BY MARGINAL COST?

A. Yes. In economic terms, marginal cost refers to the change in total costs resulting from a one-unit change in the total output of a good or service.[2] From an accounting/utility rate perspective, I equate a marginal cost to the variable cost[3] to

[2] Ansel M Sharp, Charles A. Register, and Paul W. Grimes, Economics of Social Issues, (McGraw-Hill/Irwin 2004).

[3] A variable cost changes in total proportion to changes in the related level of total activity or volume. Charles T. Horngren, Srikant M. Datar, George Foster, Cost Accounting A Managerial Emphasis, (Prentice Hall, 2003).

serve a customer. Most utility delivery service costs are fixed costs, meaning that they do not vary with the level of throughput.

Q. WHAT IS THE FIRST ANNUAL 1307(F) PERIOD IMPACTED BY THE COMMISSION'S DECISION ON THE RECOVERY OF DISCOUNTS OR WAIVERS FROM PGC CUSTOMERS?

A. The Commission has determined that the prospective PGC rate effective October 1, 2006 should not include gas costs associated with discounts or waivers unless they meet the aforementioned exceptions.

Discounting of Fuel Retention Charges

Q. HAS EQUITABLE DISCOUNTED OR WAIVED ITS FUEL RETENTION CHARGES DURING THE HISTORIC PERIOD?

A. Yes, it has. However, all of these discounts or waivers relate to contracts executed prior to the Commission's decision in Equitable's last 1307(f) proceeding.

Q. CAN YOU PLEASE EXPLAIN YOUR EXHIBIT NO. JMQ-1?

A. Yes. Equitable has negotiated delivery service agreements with seven different customers that contain a retainage rate that deviates from the distribution system average rate of 5%. Exhibit No. JMQ-1 identifies the seven transportation service customers, associated deliveries for the twelve months ended December 2005, delivery service revenue, negotiated retainage rate, retainage cost deficiency (negotiated retainage rate less 5% or some other appropriate rate based on facilities), and net delivery service revenue (delivery service revenue less retainage cost deficiency). Exhibit No. JMQ-1 also identifies whether the individual customer meets any of the Commission exceptions discussed previously. Referring to column 5 of Exhibit JMQ-1, a positive number indicates that the delivery service revenue recovered from a customer exceeds the discounted cost of fuel retainage and thereby provides a positive benefit to all customers through the contribution toward delivery service fixed cost recovery.

Q. WOULD YOU PLEASE EXPLAIN YOUR CALCULATION IN COLUMN 6 OF EXHIBIT JMQ-1?

A. Yes. In his testimony, Equitable witness Stephen Rafferty explains that each of the seven customers who have a discounted or waived fuel retainage rate also have pressure and temperature compensated meters. Based on the accuracy of such meters, Mr. Rafferty recommends that an applicable retention rate should be no more than 2.5%. For comparison purposes I have included Column 6 which calculates the retainage cost deficiency for each customer (excluding Customer 2) assuming that the appropriate retainage rate is 2.5%. When compared to the applicable delivery service revenue (Column 2) all seven customers provide a positive contribution toward the recovery of delivery service fixed costs.

Q. DO ALL CUSTOMERS IDENTIFIED ON EXHIBIT JMQ-1 MEET THE COMMISSION'S TWO PRONGED TEST?

A. With the exceptions noted below, they do. More importantly, of the total volume discounted, over 98% meet the test.

Customer 1 received a competing offer from another jurisdictional NGDC in 2003. Equitable agreed to match that offer to retain the load. During 2005, the calculated retainage cost deficiency exceeded the delivery service revenue. However, Equitable has reached a tentative agreement to restructure this agreement so that there will be recovery of the full 5% fuel retention level effective October 1, 2006 1307(f). Accordingly, there will be no prospective discount/waiver for this customer.

Customer 2 is Equitable's largest transportation customer by volume, and is served through a high pressure transmission line. This line, commonly referred to as Line M-81, was part of the old Carnegie Natural Gas Company assets that were divided into local distribution and interstate pipeline facilities pursuant to a FERC Order in 1994 in Carnegie's corporate reorganization filing. 69 FERC ¶61,364. Although Line M-81 is a transmission line, it was retained by the distribution company:

> The above-described facilities to be retained by Carnegie for local distribution purposes are located downstream of Carnegie's Jones Farm City Gate, an operational point on its system consisting of pipeline manifolds, regulators, meters, and flow control valves. Carnegie also proposes to retain these facilities, explaining that they are necessary to separate and regulate the flow of gas into Carnegie's lines in Allegheny County, Pennsylvania, that deliver gas to the ultimate consumers. This distribution service area, known as the Monongahela River Valley (Mon Valley), contains the highest concentration of Carnegie's residential and commercial customers. Since all gas entering the Mon Valley system is delivered to customers that will become Carnegie's local distribution customers following the corporate reorganization, the

> applicants state that Carnegie will need to retain the described facilities at the Jones Farm City Gate to maintain operational control over the flow of gas to distribution customers in the Mon Valley service area.

Equitable has not sought to change the classification of this pipeline, although it is the only high-pressure transmission line operated by Equitable. The line is in excellent condition and experiences little or no measurable lost and unaccounted for gas.

Customer 2 has the capability of using over a Bcf of gas per month. Due to this large volume of throughput and the relative proximity of two interstate pipelines that could provide a by-pass of Equitable's Line M-81, Equitable agreed in 2004 to offer incentives to Customer 2 to remain an LDC customer. Under the current agreement, which is due to expire on January 1, 2008, Customer 2 pays a discounted delivery rate, an aggregate monthly service charge, and 1.5% retainage. It is Equitable's belief that these rates are fully compensatory due to the condition of the pipeline serving this location. As a result, Exhibit JMQ-1 identifies no retainage cost deficiency for Customer 2 in Column 4.

If the Customer 2 were to be charged 5% retainage, its costs using a PGC commodity rate of $9.65/Mcf would increase by roughly $0.34/Mcf, or using the deliveries for the 12-months ending in August 2005 of 6.1 Bcf, some $2.1 million annually. Our best engineering estimate is that this customer could construct a by-pass delivery line to either interstate pipeline company for significantly less than $2.1 million. Therefore, if Equitable were to seek the maximum retainage rate this customer would undoubtedly pursue its by-pass alternatives. Additionally, the arrangement has worked well for both parties. As noted earlier, engineering analysis supports a retainage level of 1.5% as reasonable. Likewise, the customer has benefited from this lower rate and increased production, providing significant economic value to its employees and shareholders and to the economy in general in Western Pennsylvania.

Customer 3 is a public utility service provider on the North Shore of the Allegheny River. This customer has the present capability to use, and does use to a substantial degree, alternate fuel to run its plant. The customer also has permits allowing it to significantly increase the level of alternative fuel utilization if it should so desire. Customer 3 has demonstrated to Equitable, and has agreed to demonstrate to the Commission in this proceeding, that it was experiencing significant problems in renewing service to its large load customers. Without the discounts offered by Equitable this customer faced the probability of substantial loss of customer load. Nevertheless, even with the discounts, the delivery service revenue exceeds the retainage cost deficiency thereby providing a positive benefit to all of Equitable's customers.

Customers 4 & 7 receive service through dedicated facilities directly served by interstate pipelines. The facilities are either new or recently constructed, have measurement both in and out of the pipeline, serve no other customers and the appropriate retainage level can be accurately determined. In each case, the discounted rate exceeds the actual lost and unaccounted for gas incurred to serve the customer. Obviously, absent some level of discounts these customers would be able to by-pass Equitable and connect directly to the interstate pipeline. Nevertheless, the delivery service revenue exceeds the retainage cost deficiency thereby providing a contribution to the recovery of distribution service fixed costs.

Customers 5 & 6 have retainage discounts that were negotiated because they are competitive with another jurisdictional NGDC. Based on the Commission's recently announced policy the customers do not meet the two-pronged test.

Q. IF THE COMMISSION WERE TO DENY THE RECOVERY OF THE RETAINAGE COST DEFICIENCY FROM PGC CUSTOMERS WHAT DOES EQUITABLE REQUEST OF THE COMMISSION?

A. I have been instructed by counsel to request that the Commission issue an order declaring that delivery service agreements containing retainage discounts executed prior to the Commission's September 28, 2005, Order at Docket No. R-00050272 be declared against public policy, illegal and unenforceable and order Equitable to immediately begin negotiations with the affected delivery service customers for the purpose of obtaining a retainage rate consistent with the Commission's policy. This is necessary to create a level playing field for all parties.

Discounting/Waiving Rider B Transportation Migration Rider

Q. HAS EQUITABLE DISCOUNTED OR WAIVED ITS RIDER B TRANSPORTATION MIGRATION RIDER DURING THE HISTORIC PERIOD?

A. Yes.

Q. CAN YOU PLEASE EXPLAIN YOUR EXHIBIT NO. JMQ-2?

A. Yes. During the historic period Equitable waived its Rider B - Migration Rider for three existing customers due to competitive pressure from another NGDC. Exhibit JMQ-2 represents Equitable's demonstration of the positive benefit to customers as a result of the waiver of Rider B. It should be noted, Rider B waivers affecting each of the three customers will expire prior to October 1, 2006. Therefore there will be no impact of waivers related to the customers in Equitable's prospective PGC rate.

Discounting/Waiving Balancing Charges

Q. HAS EQUITABLE DISCOUNTED OR WAIVED BALANCING CHARGES DURING THE HISTORIC PERIOD?

A. Yes. Prior to the issuance of the Commission's guidance on the treatment of discounts and waivers Equitable had negotiated several multi-year delivery service agreements that contained discounted or waived balancing charges. As a result of the Commission's Order, Equitable modified its marketing policies on extending discounts and waivers. As these multi-year delivery service agreements expire Equitable will apply its revised marketing policies for balancing service charges.

Q. IS THERE A TRANSFER OF COST RECOVERY TO PGC CUSTOMERS AS A RESULT OF EQUITABLE'S DISCOUNTED OR WAIVED BALANCING CHARGES?

A. No. As discussed in the testimony of Equitable witness Jeffery Nehr, the Company has adjusted its balancing service requirements, and therefore its total firm capacity requirements, to a level equal to the projected balancing service costs recovered from transportation customers. As a result, Equitable is not transferring the associated costs of balancing service discounts to PGC customers.

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

Equitable Gas Company
Retainage Discounts

Exhibit JMQ-1

Customer No.	Deliveries TME 12/31/05 (Mcf) (1)	Delivery Service Revenue (2)	Negotiated Retainage Rate (3)	Retainage Cost Deficiency @ 5% (4)	Net Delivery Service Revenue (5=2+4)	Retainage Cost Deficiency @ 2.5% (6)	Exceptions: Direct Bypass	Exceptions: Service via Faciliies Requiring < 5% Retention	Exceptions: Non-Jurisdictional Offer	Exceptions: Economic Development/ Job Retention	Exceptions: Offer From Alternative Energy Source	Exceptions: Other
1	911,477	$309,902	0.0%	$ (439,813)	$ (129,911)	$ (219,906)						X
2	6,143,260	$940,912	1.5%	-	940,912	-	X	X			X	
3	763,407	$585,837	0.6%	(324,161)	261,676	(139,979)					X	X
4	193,750	$1,280,568	0.5%	(84,141)	1,196,427	(37,396)	X	X				
5	42,777	$33,600	1.0%	(16,513)	17,087	(6,192)						X
6	127,516	$63,024	3.5%	(18,459)	44,565	12,306						X
7	0	$1,308,000	1.0%	-	1,308,000	-	X	X				
	8,182,187	$4,521,844		$ (883,087)	$ 3,638,757	$ (391,167)						

Reflects mean 2005 commodity cost of purchased $ 9.65 /Mcf
System average retention rate 5%
System average retention rate 2.5%

Equitable Gas Company
Transportation Migration Rider

Exhibit JMQ-2

Customer	Annual Deliveries (Mcf) (1)	Delivery Service Revenue (2)	Negotiated Migration Rate (3)	Migration Cost Deficiency (4)	Net Delivery Service Revenue (5=2+4)	**Exceptions** Direct Bypass	Service via Faciliies Requiring < 5% Retention	Non-Jurisdictional Offer	Economic Development/ Job Retention	Offer From Alternative Energy Source	Other
1	1,623	$5,006	$ -	$ (438)	$ 4,568						X
2	5,000	$12,550	-	$ (2,450)	10,100						X
3	2,965	$8,401	-	$ (1,097)	7,304						X
	9,588	$25,958		$ (3,985)	$ 21,972						

ORIGINAL

Equitable Statement No. 3-R
Docket No. R-00061295
Witness: John M. Quinn

JUN 16 2006

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

John M. Quinn

(Prepared June 2006)

PREPARED REBUTTAL TESTIMONY OF JOHN M. QUINN

I. Witness Background

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is John M. Quinn. My business address is 225 North Shore Drive, Pittsburgh, PA 15212-5352.

Q. ARE YOU THE SAME JOHN M. QUINN WHO SUBMITTED PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes I am. My direct testimony is contained in Equitable Statement No. 4.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to the direct testimony of Office of Small Business Advocate ("OSBA") witness Brian Kalcic, Office of Trial Staff ("OTS") witness Michael J. Gruber, NRG Energy Center Pittsburgh LLC (" NRG") witness Timothy W. Merrill and Office of Consumer Advocate (" OCA") witness Jerry Mierzwa. Specifically I will respond to testimony submitted by Mr. Kalcic and Mr. Gruber related to Performance Based Rate (" PBR") Design No. 1, Mr. Merrill' s testimony concerning his negotiated delivery service rate, and Mr. Mierzwa' s testimony on fuel retention.

II. PBR Design No. 1

Q. HAVE YOU REVIEWED MR. GRUBER' S DIRECT TESTIMONY DISCUSSING PBR DESIGN NO. 1?

A. Yes I have.

Q. DO YOU HAVE ANY COMMENTS?

A. Yes. On page 6 of his prepared direct testimony OTS witness Gruber states that his counsel has advised him that if the Commission does not act to extend PBR Design No. 1 Equitable would no longer be permitted to retain any revenue or savings generated from off-system sales or capacity release transactions. Mr. Gruber further states that all revenue or savings would flow to the benefit of Purchased Gas Cost (" PGC") customers. Equitable disagrees with that position. In the alternative, Equitable' s believes that if PBR Design No. 1 is not extended the program terminates and the Company will retain 100% of the savings or revenue generated from transactions historically covered by PBR Design No. 1.

Q. HAVE THE OTS AND OSBA RECOMMENDED AN EXTENSION OF THE CURRENT PBR DESIGN NO. 1 SHARING MECHANISM?

A. Yes. Both the OTS and OSBA recommend that the current 75%/25% sharing arrangement be extended.

Q. WHAT IS EQUITABLE' S RESPONSE TO THE PBR SHARING PROPOSED BY THE OTS AND OSBA?

A. Equitable has asked the Commonwealth Court of Pennsylvania at Commonwealth Court Docket No. 687 C.D. 2006 to review and reverse the Commission' s decision in Docket No. R-00050272 related to PBR Design No. 1. While continuing to support its appeal of the Commission' s decision, Equitable will accept the OTS/OSBA recommendation to continue the 75%/25% sharing mechanism subject however to the right on the part of the Company to recover the lost shared revenue with interest at 6% if the Commonwealth Court overturns the Commission decision.

III. NRG Testimony

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF NRG WITNESS MERRILL?

A. Yes I have.

Q. DO YOU HAVE ANY COMMENTS?

A. Yes. Beginning on page 8 through page 9 of his prepared direct testimony Mr. Merrill provides several unsupported statements regarding Equitable' s delivery service rates. My initial comment is that Mr. Merrill' s testimony refers to subjects normally addressed in base rate cases. Testimony regarding delivery service rates and rates of return has no place in an annual 1307(f) proceeding and should be disregarded by the Commission.

Second, Mr. Merrill' s ratemaking experience in the natural gas industry is ambiguous at best. By his own admission (NRG Exhibit No. 1), Mr. Merrill has never performed, nor submitted testimony supporting or contesting, a study that allocates distribution system costs to each customer class (" cost allocation study"), nor has he ever performed a rate design or rate of return study. Yet, Mr. Merrill requests that the Commission accept that he is an expert in the aforementioned ratemaking issues because over the years he has been privy to negotiations between unnamed companies and unnamed LDCs and viewed an unnamed LDC cost of service study which allocated mains and service costs using a basis he does not bother to reveal.

Third, Mr. Merrill' s statements regarding Equitable' s delivery service rates are unsupported by any Equitable pro forma cost allocation study. Mr. Merrill has offered no reviewable evidence to support his statements. I am currently awaiting NRG' s responses to interrogatories served on May 24, 2006. I reserve the right to supplement my testimony related to this issue based on NRG' s responses.

Q. MR. MERRILL CONTENDS THAT EQUITABLE' S RATE SCHEDULE GDS DELIVERY SERVICE RATE IS EXCESSIVE. IS HE CORRECT?

A. No, he is not. Rate Schedule GDS, and the rates contained therein, were approved by Commission order as just and reasonable at Docket No. R-00963858, Equitable' s most recent base rate case submitted in February 1997. The maximum Commission-approved Rate Schedule GDS rate for large volume customers is $2.36/Mcf. NRG' s rate is less than a third of the rate this Commission has authorized Equitable to charge.

Q. WHAT RATE OF RETURN DID EQUITABLE ACHIEVE ACCORDING TO THE MOST RECENT QUARTERLY EARNINGS REPORT TO THE COMMISSION?

A. The most recent Quarterly Earnings Report submitted to the Commission for the twelve months ended March 2006 indicated that Equitable earned a pro forma rate of return of 5.5%. In addition, the Commission' s May 24, 2006 Quarterly Earnings Report Summary indicated that of the eight other major Pennsylvania gas utilities Equitable had the lowest reported actual and pro forma return on equity of 2.91% and 5.30%, respectively. Clearly Equitable' s GDS delivery service rate is not excessive.

Discounting of Fuel Retention, Migration, and Balancing Charges

Q. BASED ON YOUR REVIEW OF THE DIRECT TESTIMONY OF THE OTS, OCA, OSBA, AND NRG WITNESSES, DOES ANY PARTY DISPUTE THAT EQUITABLE HAS MET ITS BURDEN OF PROOF CONCERNING DISCOUNTING WITH RESPECT TO FUEL RETENTION, THE MIGRATION RIDER, OR BALANCING CHARGES?

A. No. On page 14 of his direct testimony, OCA witness Mierzwa agrees with my analysis demonstrating that Customers 1-4 and 7 satisfy the Commission' s requirements and therefore, their fuel retainage discounts may be recovered through the PGC.

The OSBA and NRG filed no testimony on this matter, while the OTS has ignored Equitable' s 2005 demonstration. Therefore, I must conclude that our methodology is acceptable and the Company' s demonstration complies with the requirements as discussed in the Commission' s Order at Docket No. R-00050272.

Q. DO YOU HAVE ANY COMMENTS ON MR. MIERZWA' S SCHEDULE JDM-5?

A. Yes. While Mr. Mierzwa has proposed no adjustments to the projected PGC rate concerning fuel retainage, he has prepared a schedule which purports to show the impact of his recommended prospective changes. There are two errors included in Schedule JDM-5 that I would like to bring to the Commission' s attention. First, on line 15 of Mr. Mierzwa' s schedule he incorrectly uses a retainage rate for all transportation throughput of 7.9%. In his direct testimony, Equitable witness Stephen Rafferty discussed at length that the appropriate retainage rate for transportation customers with temperature and pressure compensated meters should only be 2.5%. Mr. Mierzwa does not dispute Mr. Rafferty' s testimony on this matter. In his rebuttal testimony, Mr. Rafferty concludes that the current 5% retainage rate charged to transportation customers is the appropriate retainage rate. Therefore, Mr. Mierzwa has overstated the effective retainage charge to PGC customers on line 37 of Schedule JDM-5. The corrected retainage charge per the calculation proposed by Mr. Mierzwa is 6.4%.

Second, on line 33 of Schedule JDM-5, Mr. Mierzwa reflects Equitable's projected C Factor rate of $10.54/Mcf as the appropriate cost of gas. The C Factor utilized by Mr. Mierzwa includes demand costs that are irrelevant when calculating the price of gas paid by PGC customers for discounted transportation retainage charges. Demand costs are fixed costs that will not vary with the volume of gas retained by Equitable. PGC customers pay the same level of demand costs regardless of the level of Equitable's retainage rate charged to transportation customers. As a result, the cost impact on PGC customers shown on line 35 of Schedule JDM-5 is also overstated. After correcting both errors, the cost impact on PGC customers is approximately $1.4 million, not the $9 million identified by Mr. Mierzwa.

Q. HAVE YOU PREPARED A REVISED EXHIBIT CORRECTING THE AFOREMENTIONED ERRORS?

A. Yes. I have prepared Exhibit JMQ-3 correcting Mr. Mierzwa's Schedule JDM-5.

Q. ON PAGE 16 OF HIS DIRECT TESTIMONY MR. MIERZWA RECOMMENDS CHANGES TO THE COMMISSION'S NEWLY

ESTABLISHED POLICY RELATED TO RETAINAGE DISCOUNTS. DO YOU HAVE ANY COMMENTS?

A. Yes. Mr. Mierzwa recommends that the Commission establish a new condition that must also be met before fuel retainage discounts are recoverable from PGC customers. The OCA recommends that an NGDC not discount fuel retention charges to a transportation customer by a greater percentage than it has discounted its applicable base rate. I disagree. The Commission recently established a net benefits test for fuel retainage discounting in its Final Order at Docket No. R-00050272. The OCA did not raise this issue in testimony, or ask the Commission for reconsideration of its order establishing the net benefits test. The Commission has correctly decided that the discounting of retainage is acceptable if the base rate charges recover the marginal cost of delivering gas to ensure a contribution to fixed costs.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

Exhibit JMQ-3

EQUITABLE GAS COMPANY

Estimated Impact of Retainage Recommendations on PGC Customers
(Mcf)

Line No.				Source/Calculation
1	Projected 2006 PGC Period Volumes			
2				
3	PGC Sales		24,249,100	OCA-I-2
4	Transportation		22,333,591	OCA-I-2
5				
6	Total		46,582,691	Lines 3 + 4
7				
8	Fuel Charge Discounted Volumes		7,499,641	OCA-II-16, less Customer 1
9				
10	Total Non-Fuel Discounted Volumes		39,083,050	Line 6 - Line 8
11	Total Transportation Non-Fuel Discounted Volumes		14,833,950	Line 4 -8
12				
13	Transportation retainage rate	5.00%		Witness Stephen Rafferty testimony
14				
15	Required Retainage		2,451,721	(Line 6/(1 - Line 13) - Line 6
16				
17	Retainage from Discounted Volumes		109,734	OCA-II-16
18				
19	Additional Retainage to be Recovered		2,341,986	Line 15 - 17
20				
21	Retainage as a Percent of Non-Discounted Volumes	5.99%		Line 19 / Line 10
22				
23	Current Retainage Charge	5.00%		Per Tariff
24				
25	Required Increase in Retainage Charge	0.99%		Line 21 - 23
26				
27	Retainage Collected from Transportation Customers at Existing Charge		780,734	(Line 11/(1 - Line 23) - Line 11
28				
29	Retainage from Transportation Customers at Sytem Average		945,561	(Line 11/(1 - Line 21) - Line 11
30				
31	Overcollection of Retainage from PGC Customers		164,827	Line 29 - 27
32				
33	Commodity Cost of Gas		$8.5760	Item 53.64(a), Section I, Part A, Sheet 1
34				
35	Cost Impact on PGC Customers		$1,413,555	Line 31 x 33
36				
37	Effective Retainage Charge to PGC Customers		6.4%	(Line 19 - 27)/ Line 15

ORIGINAL

Equitable Statement No. 4
Docket No. R- 00061295
Witness: Stephen C. Rafferty
Date: JUN 1 6 2006

RECEIVED

JUN 2 1 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

EQUITABLE GAS COMPANY

Prepared Direct Testimony of

Stephen C. Rafferty

(Prepared April 2006)

DOCUMENT FOLDER

DOCKETED
SEP 2 2 2006

PREPARED DIRECT TESTIMONY OF STEPHEN C. RAFFERTY

WITNESS BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen C. Rafferty. My business address is 225 North Shore Drive, Pittsburgh, Pennsylvania 15212.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Equitable Gas Company ("Equitable" or the "Company"), a division of Equitable Resources, Inc., as Vice-President, Utility Asset Management.

Q. PLEASE STATE YOUR PRIMARY DUTIES IN YOUR CAPACITY AS VICE-PRESIDENT, UTILITY ASSET MANAGEMENT.

A. I have overall responsibility for ensuring that Equitable has sufficient natural gas supplies and delivery service capacity to meet the needs of the customers on its system, consistent with least cost procurement policy and practices. In addition, I have the responsibility for the administration of Equitable's end-user transportation program.

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL WORK EXPERIENCE.

A. I attended the University of Pittsburgh and earned a Bachelor of Science Degree in Civil Engineering in 1986. I continued my education with graduate work and earned a Masters in Business Administration (MBA) degree from the Indiana University of Pennsylvania in 1990. I have also completed several technical and industry related courses and seminars pertaining to my job responsibilities.

Professionally, I began my career in 1986 as a Civil Engineer with the Pennsylvania Department of Transportation. In 1988, I accepted a position with Equitable Gas Company as a Technical Fieldman. In 1989, I was promoted to the position of Customer Service Foreman. In 1991, I was promoted to the position of District Foreman. These operational positions were within the Distribution Department and included responsibility for utilizing a unionized labor force to schedule work and complete assignments. These positions provided an excellent background in understanding gas pressures and flows and the manner in which supplies are distributed within the Company's service territories. In 1995, I was promoted to the position of Load Research and Planning Coordinator in the Gas Management Department with responsibility for gas supply / demand forecasting. In January 1997, I was promoted to the position of Manager- Gas Acquisition and Planning. In January 1999, I was promoted to Director, Gas Acquisition. In January 2000, I was promoted to Director, Gas Acquisition & Management. In March 2004, I was promoted to my current position as Vice-President, Utility Asset Management.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes. I submitted testimony before the Pennsylvania Public Utility Commission in Equitable's 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004 and 2005 1307(f) proceedings at Docket Nos. R-00973895, R-00984279, R-00994601, R-00005067, R-00016132, R-00027135, R-00038166, R-00049154 and R-00050272, respectively. In addition, I testified before this Commission in Equitable's 1998 Service Expansion

Application at Docket No. A-121100 F0003 and in the Company's 1999 restructuring proceeding at Docket No. R-00994784.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to:

- sponsor certain portions of the Company's 2005 1307(f) filing;
- describe briefly Equitable's natural gas acquisition strategy including the Company's use of risk management tools and its proposed formal hedging program;
- identify the Company's projected gas supply sources;
- explain the use of interstate pipeline services during the historic period;
- briefly discuss Equitrans' general rate case at Docket No. RP04-97 and the impact their proposal and settlement, including the proposed rates and refund, would have on the Company's gas acquisition costs;
- discuss the contractual changes to the interstate pipeline contracts that the Company anticipates during the Interim and Projected periods including the Company's efforts to generate gas cost savings by monetizing the value between the different delivery points associated with a Dominion Transmission storage and transportation contract;
- briefly explain Performance Based Rate ("PBR") Design No. 1 and the Company's desire to modify this incentive mechanism;
- demonstrate that there were positive benefits to customers as a result of the

Company's discounts or waivers of certain tariff provisions;

- report on the actions taken by the Company in response to the Energy Information Administration ("EIA") reporting erroneous storage information that was submitted by Dominion Transmission Inc.

RESPONSIBILITY FOR 1307(F) FILING

Q. WHICH PORTIONS OF THE COMPANY'S 2006 1307(F) FILING ARE YOU SPONSORING?

A. The specific sections of the filing which I am sponsoring are listed on Attachment A to my direct testimony. The majority of these sections are self-explanatory, therefore, I will not address them individually in my testimony. However, I will answer any questions which may arise during the course of this proceeding concerning these sections.

EQUITABLE'S GAS ACQUISITION STRATEGY

Q. PLEASE BRIEFLY DESCRIBE EQUITABLE'S GAS ACQUISITION STRATEGY.

A. Equitable purchases its gas supplies based on an acquisition strategy that minimizes gas purchase costs while assuring there is adequate, reliable supply. Assurance of "adequate and reliable" supply requires that planning be based on the need to maintain deliverability during peak demand periods under design day conditions. In addition, factors including historical dependability and reliability are considered. Finally, assurance of "adequate and reliable" supply also requires that gas quality and operating pressures be consistent with the Company's needs and qualitative standards. This strategy is pursued within the scope of the Company's existing operational capabilities – both physical and contractual - and with the realization that the goals of minimizing gas costs and maximizing reliability often conflict with one another. The major portion of Equitable's current portfolio of firm gas supply agreements consists of various index-related prices and permits the Company to buy long-term firm gas under base load arrangements, spot arrangements, or combinations of both. These contracts ensure reliable deliverability and provide geographical diversity to the Company's gas supply portfolio.

Q. DOES EQUITABLE'S GAS ACQUISITION STRATEGY EMPLOY THE USE OF RISK MANAGEMENT TOOLS?

A. Yes. Equitable has the option, with certain gas supply contracts, to establish a fixed price for the gas supplies prior to the month of actual delivery. Equitable does occasionally exercise this option to purchase a portion of its gas supplies at market prices for varying lengths of time, similar to the "dollar-cost averaging" technique utilized in the financial markets to reduce the average share cost to the investor. (Dollar-cost averaging is the technique of investing a fixed sum at regular intervals regardless of financial market movements). Beginning January 2002, Equitable began using Planalytics' Weathernomics Gas Buyer™, to assist in natural gas purchases more than one month in advance of the month of flow. This web-delivered tool aids in natural gas price analysis and enables users to better identify weather-driven changes in gas prices up to one year into the future. In addition, the Company's efforts to retain and attract local Appalachian supplies have required the Company to occasionally establish fixed market prices. This strategy attempts to encourage the development of new, additional supplies and also attempts to reduce the price volatility and operational uncertainties accustomed to local Appalachian supply. These strategies provide pricing diversification with respect to the gas supply portfolio and in certain circumstances, the use of fixed price gas contracts may serve a useful purpose in protecting ratepayers from price volatility.

Q. DOES THE COMPANY HAVE A FORMAL HEDGING POLICY?

A. No. At this time, the Company does not have a formal hedging policy. However, the Commission's Order in last year's proceeding, at Docket No. R-00050272, directed the Company to submit a formal hedging policy prior to this year's filing.

Q. HAS THE COMPANY SUBMITTED THE FORMAL HEDGING PROGRAM AS DIRECTED BY THE COMMISSION?

A. Yes. The Company's formal hedging program proposal was submitted to all Parties as directed by the Commission's Order. I have attached to my Direct Testimony, as Attachment B, the Company's Proposed 2006 Gas Supply Hedging Program ("Program"). Equitable will not proceed with this Program unless there is a consensus among the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA") and the Office of Trial Staff ("OTS") that this Program is appropriate and is consistent with least cost purchasing obligations.

GAS SUPPLY SOURCES

Q. WHAT ARE THE SOURCES FROM WHICH EQUITABLE PURCHASES NATURAL GAS TO MEET THE NEEDS OF ITS CUSTOMERS?

A. Equitable's gas supply portfolio consists of purchases made from the Southwest and Appalachian producing regions of the country.

Q. WOULD YOU DESCRIBE IN DETAIL THE SOUTHWEST PORTION OF THE COMPANY'S SUPPLY PORTFOLIO?

A. Equitable purchases a majority of its gas supply from the Southwest production areas, namely the Gulf of Mexico, Texas and Louisiana. Equitable has concentrated on diversifying its supply portfolio by purchasing supplies from numerous sources that conform to Equitable's acquisition goals. Gas supplies that are purchased from the Southwest production areas continue to be an essential part of Equitable's supply portfolio. These supplies, in conjunction with the Appalachian supplies, are used not only to meet the requirements of customers during peak demand periods, but also to inject gas into storage during low demand periods. The majority of Equitable's Southwest supply contracts were executed for the winter season only (November - March). These firm supplies may be used in conjunction with interstate spot market supplies, i.e., purchases having a term of one month or less, to achieve a level of reliability necessary to meet customer demand requirements, particularly during non-peak demand periods. Equitable continues to use the interstate spot market, on an economic basis, to either satisfy non-peak demand requirements or for storage injection purposes. This supply strategy of committing to term contracts during the winter months to ensure reliability and utilizing the spot market during the summer months has not only allowed Equitable to minimize producer demand charges, but has also allowed Equitable to utilize its transportation capacity on upstream pipelines in an efficient manner.

Q. WOULD YOU ALSO DESCRIBE IN DETAIL THE APPALACHIAN PORTION OF THE COMPANY'S SUPPLY PORTFOLIO?

A. In addition to its Southwest supply portfolio, Equitable has an aggressive local Appalachian production gas purchase strategy which is designed to attract new supplies to its system. This strategy consists of various pricing mechanisms, ranging from fixed pricing options to several different index-pricing options. Multiple pricing options have enabled the Company to encourage the development of new supplies while attempting to reduce price volatility and operational uncertainties that have been customary within the natural gas industry. Equitable's Appalachian gas purchase agreements have varying terms, up to and including existing life-of-the-well agreements, which provide a stable source of supply.

Equitable's Appalachian supply includes two types: Appalachian-Direct and Appalachian-Transport. Appalachian-Direct refers to Appalachian supplies that are delivered directly into the Company's distribution system. Appalachian-Transport refers to those Appalachian supplies that must be transported via Equitrans, i.e., FTS-31 or CIPCO, to the Company's distribution system.

Q. WHAT PERCENTAGE OF TOTAL SUPPLY DOES EACH SUPPLY SOURCE IDENTIFIED ABOVE REPRESENT DURING THE PROJECTED PERIOD?

A. During the projected period (12 month period ending September 30, 2007), Equitable anticipates that its total supply will consist of the following purchases: approximately 11.147 million dekatherms ("dth") or roughly 41% from Southwest production area sources and approximately 16 million dth or roughly 59% from other Appalachian sources, including Appalachian-Transport and Appalachian - Direct.

Q. HAVE THE CURRENT SUPPLY SOURCES CHANGED WHEN COMPARED TO THE COMPANY'S 2005 1307(F) FILING?

A. Yes. Equitable's 2005 1307(f) filing indicated that its total supply would consist of approximately 15 million dth or roughly 52% from Southwest production area sources and approximately 14 million dth or roughly 48% from other Appalachian sources, including Appalachian-Transport and Appalachian - Direct.

Q. WHY HAVE THE COMPANY'S SUPPLY SOURCES CHANGED?

A. The Company continues to increase the amount of Appalachian – Direct supplies that it purchases. The continuous improvements regarding the Company's Northern Asset Optimization Program ("NAOP") affords Equitable the opportunity to obtain additional low-cost sources of supply and also reduce its dependency on upstream interstate pipelines. (Please refer to the Direct Testimony of Equitable Witness Rafferty, identified as Statement No. 2, submitted during the 2004 proceeding at Docket No. R-00049154, for additional information regarding the NAOP).

Q. ARE THERE OTHER CONSIDERATIONS ASSOCIATED WITH THIS ADDITIONAL APPALACHIAN SUPPLY?

A. Yes. The Company's efforts have reduced the dependency on gas supplies originating in the Southwest or Gulf Coast areas of the Country. These Appalachian supplies have been extremely important especially when one considers the recent impact that Hurricanes Katrina, Rita and Wilma had on the Gulf Coast production and infrastructure.

INTERSTATE PIPELINE SERVICES (HISTORIC PERIOD)

Q. WHAT WERE THE COMPONENTS OF EQUITABLE'S INTERSTATE PIPELINE SERVICES DURING THE HISTORIC PERIOD?

A. Equitable purchases a mix of pipeline services that replicates the reliability of the bundled sales service that was available prior to FERC Order No. 636. During the historic reconciliation period the unbundled services included firm pipeline transportation services provided by Equitrans, L.P., ("Equitrans"), Texas Eastern Transmission ("TETCO"), Dominion Transmission, Inc. ("Dominion") and Carnegie Interstate Pipeline Company ("CIPCO"). In addition to these firm pipeline transportation services, the Company also received firm storage services from Equitrans and Dominion. Equitrans also provides a firm no-notice transportation service to Equitable. In addition to these interstate pipeline services, Equitable purchases Appalachian supply that is delivered directly into its distribution system.

Equitable utilizes Equitrans' interstate pipeline interconnections with TETCO and Dominion and CIPCO's interstate pipeline interconnections with TETCO and Equitrans to manage supplies and deliveries at necessary flow rates to meet the demand requirements of Equitable's largely weather-sensitive firm customers. These various interconnections are critical in providing sufficient pressures and supplies when peak demand periods occur. These interstate pipeline interconnections are used in conjunction with the storage and transportation services on Equitrans to ensure reliable, continuous service to all of Equitable's firm customers.

Q. CAN YOU DESCRIBE THE TERMS AND CONDITIONS OF THE PIPELINE SERVICES THAT EQUITABLE PURCHASED FROM EQUITRANS DURING THE HISTORIC PERIOD?

A. Equitable has contracts with Equitrans for firm transportation, no-notice transportation, baseload storage and peaking storage services. The Company receives firm transportation service under Equitrans' Rate Schedule FTS. Under this rate schedule, Equitable transports gas up to the maximum daily quantity. Equitrans assesses a transportation or usage charge for the actual quantities that are delivered to the customer during the month. In addition, Equitrans assesses a seasonal demand charge that is different for the winter period (November 1 through March 31) than it is for the summer period (April 1 through October 31). Both charges are calculated by multiplying the appropriate seasonal demand charge by its respective maximum daily contract quantity.

Equitrans' no-notice firm transportation service ("noft") allows the Company to receive or deliver gas on demand up to its firm entitlement on a daily basis without incurring daily balancing and scheduling penalties. For this service, Equitrans assesses a transportation or usage charge for the actual quantities it delivers to Equitable during the month. As with FTS service, there are winter and summer demand charges associated with this contract that are calculated in a similar fashion.

In addition to the firm pipeline transportation and the no-notice firm transportation service, Equitable has baseload storage services and peaking storage services with Equitrans. The baseload storage services are provided under the Equitrans SS-3 and 115-SS Rate Schedules. Both of these rate schedules provide a 115 day storage service. The maximum daily withdrawal quantity under these rate schedules is 1/115 of the total annual storage quantity. The Company may withdraw, however, 110% of the maximum daily withdrawal quantity until the remaining storage inventory is reduced to 17% of the total annual storage quantity. Once this inventory level is achieved, the Company is restricted to withdrawing only 100% of the maximum daily withdrawal quantity.

The peaking storage services are provided under the Equitrans 60-SS, 30-SS and 10-SS Rate Schedules. The maximum daily withdrawal quantity is based on 1/60, 1/30 and 1/10, respectively, of the total annual storage quantity ("tasq"). This gas can be withdrawn on any day during the winter season, provided the Company has gas in storage under the respective agreement. This service also permits the Company to withdraw and inject gas year-round on a best efforts basis.

For each storage service, Equitrans assesses four charges which are applicable the entire year. These charges consist of the storage demand charge, the storage space charge, the storage injection charge and the storage withdrawal charge. The storage demand charge is equal to the storage demand rate multiplied by the maximum daily withdrawal quantity ("mdwq"). The storage space charge is equal to the storage space rate multiplied by the total annual storage quantity. The storage withdrawal and injection charges are variable charges which are assessed on the actual volumes withdrawn or injected during the month.

Q. PLEASE IDENTIFY THE CONTRACTUAL VOLUMES ASSOCIATED WITH EACH OF THE FIRM TRANSPORTATION AND FIRM STORAGE SERVICES THAT EQUITABLE HAD DURING THE HISTORIC PERIOD.

A. Attached to my testimony as Equitable Exhibit SCR-1 is a summary of the firm transportation and firm storage services that Equitable had during the historic period. This combination of firm storage and firm transportation on Equitrans provided Equitable with 511,619 Dth of peak day deliverability. It should also be noted that all of the Equitrans contracts had an expiration date effective March 31, 2006.

Q. DID THE COMPANY TERMINATE THESE CONTRACTS?

A. Yes. All of the Equitrans contracts were terminated effective March 31, 2006. On December 1, 2003, Equitrans filed a general rate case, at Docket No. RP04-97, which proposed to revise certain terms and conditions of its tariff. The filing and proposed settlement also included changes that have a direct impact on the deliverability the Company had historically received. I will discuss these changes and their impact to the Company in more detail later in my testimony.

Q. HAS THE COMPANY RENEWED OR EXTENDED ANY OF THESE CONTRACTS?

A. Yes. I will discuss in more detail later in my testimony which contracts were renewed or extended. Specifically, these topics are discussed in the Section identified as

Contractual Changes (Interim and Projected Periods).

Q. ARE THE 511,619 DTH OF EQUITRANS ENTITLEMENTS, IDENTIFIED IN EQUITABLE EXHIBIT SCR-1, CONSISTENT WITH THE DESIGN DAY ANALYSIS PRESENTED IN LAST YEAR'S PROCEEDING?

A. Yes. During last year's proceeding, Equitable Witness Nehr presented a design day analysis that indicated Equitable required 515,101 dth of firm requirements on Equitrans. Basically, Equitable extended, for an additional year, all of the services it formerly had with Equitrans, with the exception of Rate Schedule SS-3.

Q. WHY DID EQUITABLE NOT EXTEND RATE SCHEDULE SS-3 FOR AN ADDITIONAL YEAR?

A. Based upon Equitable's 2005 design day analysis, the Rate Schedule SS-3 storage service was not required.

Q. DID EQUITABLE REFLECT THE ELIMINATION OF THE SS-3 STORAGE IN THE CURRENT FILING?

A. Yes. Last year's filing contained $1,843,444 in annual demand charges associated with Rate Schedule SS-3. These costs have been removed and are <u>not</u> included in this year's filing since they were never incurred.

EQUITRANS' GENERAL RATE CASE

Q. PLEASE PROVIDE A BRIEF SUMMARY OF EQUITRANS' CURRENT GENERAL RATE CASE.

A. Equitrans' last rate case ended in a settlement that required the filing of a new rate case no later than August 1, 2003. Because of the acquisition of Carnegie Interstate Pipeline Company ("CIPCO"), this deadline was extended to December 1, 2003. Equitrans filed their general rate case on December 1, 2003, at Docket No. RP04-97. In this filing, Equitrans proposed to revise the terms and conditions of their tariff along with requesting a general rate increase. This filing also included changes in compliance with Order No. 637 pertaining to capacity segmentation and established initial rates for the CIPCO District.

Q. WHAT CHANGES DID EQUITRANS MAKE TO THE TERMS AND CONDITIONS OF THEIR TARIFF?

A. The significant changes that were made by Equitrans included gas quality standards, storage ratchets, a segmentation proposal and both security cost and retainage trackers.

Q. DOES THE COMPANY CONSIDER THESE CHANGES TO THE TERMS AND CONDITIONS OF EQUITRANS' TARIFF TO BE SIGNIFICANT?

A. Yes, but some more than others. For example, the retainage tracker could be significant, but it will be based on actual data that could be reduced over time. On the other hand, a significant change by Equitrans involves the implementation of storage ratchets. Historically, Equitrans' storage ratchets applied to Part 284 storage services provided under Rate Schedules 10-SS, 30-SS, 60-SS and 115-SS. These ratchets were implemented based on the Total Storage Inventory of all of Equitrans' storage reservoirs. These ratchets could only be imposed when Equitrans' total storage reservoir withdrawal capability was insufficient to meet the total level of firm storage withdrawals on that particular day. The following ratchets applied to each firm storage customer:

TSI	RATCHET
Greater than or equal to 44,140 MMcf	100% of mdwq
Less than 44,140 MMcf but greater than or equal to 37,000 MMcf	61% of mdwq
Less than 37,000 MMcf but greater than or equal to 31,990 MMcf	15% of mdwq
Less than 31,990 MMcf	0% of mdwq

Q. WHAT CHANGES DID EQUITRANS MAKE TO ITS STORAGE RATCHET PROVISIONS?

A. Equitrans has implemented two new storage ratchets that impact the base-load services (60-SS, 115-SS and SS-3) as well as the peaking storage services (10-SS and 30-SS).

Q. PLEASE IDENTIFY THE CHANGES TO THE BASE-LOAD STORAGE RATCHETS IN DETAIL.

A. In summary, Equitrans' base-load ratchets are based upon the level of inventory each customer has in storage. As a customer's total storage inventory decreases so will the associated mdwq. More specifically, the base-load ratchets are as follows:

STORAGE BALANCE	RATCHET
Less than or equal to 35% but greater than 16%	92% of mdwq
Less than or equal to 16% but greater than 10%	70% of mdwq
Less than 10%	63% of mdwq

In addition to this change, Equitrans also requires that each customer have at least the following percentages in their storage inventory on each day during the winter season (November 1st through March 31st):

Through December 31st customers must have in inventory at least 35% of their tasq;
Through January 31st customers must have in inventory at least 35% of their tasq;
Through February 28th customers must have in inventory at least 15% of their tasq.

Q. WHAT ARE EQUITRANS' CHANGES TO THEIR PEAKING STORAGE SERVICES?

A. Equitrans reduces the storage customers' mdwq on a progressive, time-based methodology, regardless of the actual weather experienced or the actual storage inventory on hand. This change only applies to the peaking storage services, i.e., Rate Schedules 10-SS and 30-SS and is identified below:

TIME PERIOD	RATCHET
November 1st through January 31st	100% of mdwq
February 1st through February 15th	75% of mdwq
February 16th through February 28th	50% of mdwq
March 1st through March 31st	25% of mdwq

Q. WHAT IMPACT DO THESE STORAGE RATCHETS HAVE ON THE COMPANY'S ABILITY TO MEET ITS FIRM SALES OBLIGATIONS?

A. In addition to potentially incurring additional gas costs to meet its firm sales obligations, the Company is faced with increased complexity in planning the use of the 10-SS, 30-SS and 60-SS storage services.

Q. WOULD YOU PLEASE EXPLAIN HOW THESE STORAGE RATCHETS COULD RESULT IN ADDITIONAL GAS COSTS?

A. The Company's combined mdwq associated with the 10-SS and 30-SS peaking-storage services is 163,404 dth. During the period November 1 through January 31, the Company has the ability to withdraw 100% of the mdwq or 163,404 dth. During the period February 1 through February 15, the mdwq available to the Company is reduced by 25% to 122,553 dth. The total mdwq reduction during this period is 40,851 dth (163,404 - 122,553). During the period February 16 through February 28, the mdwq available to the Company is reduced by 50% to 81,702 dth. The total mdwq reduction during this period is 81,702 dth (163,404 - 81,702). During the period March 1 through March 31, the mdwq available to the Company is reduced by 75% to 40,851 dth. The total mdwq reduction during this period is 122,553 dth (163,404 - 40,851).

In the event the Company's service territory experiences significantly colder than normal weather during March, which at times can happen, the Company's deliverability will be reduced by 122,553 dth/day because of these proposed ratchets. Again, these ratchets are implemented March 1. Weather experienced during early March can be as cold, or colder, than the weather experienced during the middle of February. As a result, the Company would be forced to purchase additional supplies, at market prices and if available, to replace this lost deliverability.

Q. ARE THERE OTHER CHANGES THAT EQUITRANS HAS SUBMITTED IN THEIR GENERAL RATE CASE THAT COULD POTENTIALLY IMPACT THE COMPANY'S FUTURE GAS COSTS?

A. Yes. In addition to their general rate increase, Equitrans has also eliminated the discounted billing determinants for firm transportation related to firm storage services.

Q. WHAT IS THE OVERALL IMPACT OF EQUITRANS' GENERAL RATE CASE INCREASE TO THE COMPANY'S PURCHASED GAS COSTS?

A. I have attached to my testimony as Equitable Exhibit SCR-2 a schedule that identifies the historical annual charges paid to Equitrans and CIPCO for firm transportation and firm storage services. Based on these historical rates before *Equitrans* filed their general rate case, Equitrans and CIPCO were paid approximately $32,300,000 annually. Attached to my testimony as Equitable Exhibit SCR-3 is another schedule that reflects the changes proposed by Equitrans in its general rate case. If those rates had been approved as filed, the Company's annual charges for Equitrans' and CIPCO's services would increase to $40,085,508. Therefore, the impact to the Company's annual purchased gas costs would have been an annual increase of nearly $8 million. Equitrans instituted their higher filed rates on September 1, 2004, therefore, this analysis was completed utilizing the capacity entitlements that were in effect during 2003.

Q. DOES THIS INCREASE INCLUDE COSTS ASSOCIATED WITH NO-NOTICE FIRM TRANSPORTATION?

A. Yes. The total increase does include costs associated with no-notice firm transportation. Pursuant to the Commission's Order in last year's proceeding, Equitable now includes the costs of no-notice with other costs to be recovered from PGC rates, and the balancing charge paid by all customers is credited to the PGC.

Q. AT THIS TIME, HAS EQUITRANS' GENERAL RATE CASE BEEN FINALIZED?

A. No. On December 9, 2005, Equitrans submitted to the Federal Energy Regulatory Commission ("FERC") an offer of settlement. If approved, the settlement will resolve all issues arising out of Docket Nos. RP-05-164-000, RP04-97-000, RP05-105-000 and RP04-203-000, and related court appeals. All of the active participants in those proceedings either support or do not oppose the settlement. As of April 1, 2006, FERC had not issued a final order approving the settlement. If adopted as filed, the settlement will provide all parties with future rate and tariff certainty, along with providing customers with a significant level of refunds.

Q. CAN YOU EXPLAIN WHY *EQUITRANS* WILL ISSUE RATE RUFUNDS?

A. Since September 1, 2004, Equitrans has been collecting its filed-for rates, subject to refund, while the parties attempted to resolve the various issues related to identifying an appropriate cost of service. As noted above the settlement should provide a significant reduction for Equitable's customers from the current level of rates.

Q. HAS EQUITRANS ISSUED ANY RATE REFUNDS AT THIS TIME?

A. No. At this time, it is unclear when this refund will be received. However, soon after FERC issues a Final Order resolving the case, Equitable will receive a refund estimated to be in excess of $9 million.

Q. HAS THE COMPANY REFLECTED ANY OF THE RATE REFUNDS IN THIS YEARS FILING?

A. No. At this time, the Company has not reflected any of the rate refunds in this years filing. Although Equitable expects to receive a refund estimated to be in excess of $9 million, it has already petitioned the Commission, at Docket No. P-00052192, for authorization to use a portion of the Equitrans refund to benefit low income customers.

Q. DID EQUITABLE RECEIVE A COMMISSION ORDER APPROVING THE PETITION?

A. Yes. Equitable received a Commission Order on December 15, 2005, that granted our petition for authorization to use a portion of an Equitrans refund to benefit low income customers. During the 2005-2006 winter heating season, Equitable advanced, in anticipation of receiving the Equitrans refund, some $7 million to re-establish and maintain service to low-income and other needy customers served by Equitable.

Q. IS THE ENTIRE REFUND BEING USED TO BENEFIT LOW-INCOME CUSTOMERS?

A. No. Equitable is using some $7 million of the refund to benefit low-income customers. As I mentioned previously, Equitable anticipates a refund in excess of $9 million. The difference between the actual refund amount received from Equitrans and the $7 million used for the benefit of low-income customers will be reflected in the future purchased gas costs.

Q. EXCLUDING THE RATE REFUNDS, WHAT IS THE OVERALL IMPACT TO PGC CUSTOMERS FROM THE EQUITRANS GENERAL RATE CASE SETTLEMENT?

A. The original filed rates would have increased purchased gas costs by nearly $8 million on an annual basis. In an attempt to reduce the rate increase as well as minimize the impact of the recently approved storage ratchets, Equitable has restructured some of the services that it formerly had with Equitrans. Specifically, Equitable has eliminated the Rate Schedule 10-SS and 30-SS storage services. Later in my testimony, I will discuss in detail the contractual and service changes that will occur as a result of Equitrans' general rate case settlement and the benefits to PGC customers. The combination of the settled rates and the restructuring of services will provide annual demand charges equal to $34,613,180. These charges are reflected in Equitable Exhibit SCR-4. In summary, the overall impact to PGC customers from the recent Equitrans general rate case settlement is an annual increase of approximately $2,295,067 [($34,613,180 (Exhibit SCR-4) - $32,318,113 (Exhibit SCR-2)].

CONTRACTUAL CHANGES (INTERIM AND PROJECTED PERIODS)

Q. ARE THERE ANY PROPOSED CONTRACTUAL CHANGES FOR THE INTERIM OR PROJECTED PERIODS?

A. Yes. First of all, the Company has renewed its firm transportation and firm storage contracts with Equitrans. As I mentioned previously, all of the Equitrans contracts expired March 31, 2006. Secondly, the Company has extended the firm transportation and firm storage contracts it has with Dominion.

Q. PLEASE DESCRIBE THE EQUITRANS FIRM TRANSPORTATION AND FIRM STORAGE CONTRACTS REFLECTED IN THE FILING FOR THE INTERIM AND PROJECTED PERIODS.

A. For the interim and projected periods, the Company has reflected firm transportation and firm storage capacity on Equitrans that is consistent with the results of the 2006 design day analysis presented by Equitable Witness Jeffrey Nehr.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S MOST RECENT DESIGN DAY ANALYSIS?

A. The results of the study presented by Equitable Witness Jeffrey Nehr suggest the projected design peak day firm requirements are 480,883 dth and the projected firm requirements on Equitrans should be approximately 465,883 dth, net of Appalachian direct-feed supplies.

Q. HAS THE COMPANY ENTERED INTO CONTRACTS WITH EQUITRANS THAT MEET THIS LEVEL OF PROJECTED FIRM REQUIREMENTS?

A. Yes. I have identified in Equitable Exhibit SCR-5 the firm capacity that the Company expects to have on Equitrans during the interim and projected periods. The total contractual capacity is 458,091 dth and the total annual cost for this capacity is approximately $35 million, as reflected in Equitable exhibit SCR-4.

Q. CAN THE COMPANY OPERATE IN A SAFE AND RELIABLE MANNER WITHOUT THE FIRM STORAGE AND FIRM TRANSPORTATION CONTRACTS WITH EQUITRANS?

A. No. I mentioned previously that Equitable utilizes Equitrans' interstate pipeline interconnections with TETCO and Dominion and CIPCO's interstate pipeline interconnections with TETCO and Equitrans to manage supplies and deliveries at necessary flow rates to meet the demand requirements of Equitable's largely weather-sensitive firm customers. These various interconnections are critical in providing sufficient pressures and supplies when peak demand periods occur. As a result of this unique relationship, Equitable requires the storage and transportation services on Equitrans, and the interstate pipeline interconnections Equitrans has with other interstate pipelines, to ensure reliable, continuous service to all of Equitable's firm customers.

Q. HOW DID THE COMPANY DETERMINE THE FIRM CAPACITY PORTFOLIO

ON EQUITRANS THAT IS REFLECTED IN EQUITABLE EXHIBIT SCR-5?

A. The Company considered multiple alternative capacity scenarios that satisfied the 465,883 dth of projected firm requirements on Equitrans. However, most of these scenarios simply involved reducing the existing services on Equitrans. For instance, the Company could have reduced the mdwq associated with Rate Schedule 10-SS or Rate Schedule 115-SS by an amount that reduced the old capacity portfolio to a level that equaled the new 2006 design day projections, i.e., 465,937 dth. However, this action would have resulted in Equitrans increasing the costs to the other remaining services. In an attempt to minimize the rate increase associated with Equitrans' general rate case the Company decided to restructure its storage contracts and acquire as much storage as possible.

Q. HOW COULD THE COMPANY MINIMIZE A POTENTIAL RATE INCREASE BY RESTRUCTURING THE STORAGE SERVICES?

A. The Company firmly believes that by acquiring additional storage it has the ability to minimize and potentially reduce gas costs based on the seasonal differential in gas prices. Ignoring all of the operational benefits associated with storage, namely the ability to balance daily and seasonal variations in demand, there are usually significant gas price differentials between the summer injection season and the winter withdrawal season.

Q. PLEASE DESCRIBE THIS SEASONAL DIFFERENTIAL IN MORE DETAIL.

A. The seasonal differential has two components: the gas price differential and the basis differential. Typically, the summer injection season gas prices are lower than the winter withdrawal season gas prices. Attached to my direct testimony as Equitable Exhibit SCR-6 is a schedule that identifies the New York Mercantile Exchange ("NYMEX") prices for the period April 2006 through March 2007. These are indicative prices as of March 31, 2006. The average summer (April 2006 through October 2006) NYMEX price was \$7.60/dth. The average winter (November 2006 through March 2007) NYMEX price was \$10.23/dth. The difference, \$2.63/dth, represents the seasonal NYMEX gas price differential. The basis differential, which represents the price differential between the NYMEX (Henry Hub) and the physical delivery location (Dominion Appalachia – South Point), has seasonal variability as well. On March 31, 2006, the basis differential was \$0.20/dth higher for the winter season than it was during the summer season. Therefore, the total combined seasonal differential reflected on March 31, 2006, is approximately \$2.83/dth (\$2.63 + \$0.20).

Q. HOW MUCH ADDITIONAL STORAGE WAS THE COMPANY ABLE TO ACQUIRE?

A. The Equitrans storage contracts that recently expired on March 31, 2006 had a combined storage quantity equal to 8,969,464 dth. The new Equitrans storage contracts that are effective April 1, 2006 have a combined storage quantity equal to 12,756,653 dth. Therefore, the additional storage that the Company was able to acquire is 3,787,189 dth (12,756,653 - 8,969,464).

Q. ALTHOUGH THE TOTAL STORAGE QUANTITY HAS INCREASED SIGNIFICANTLY, HASN'T THE DELIVERABILITY DECREASED?

A. Yes, it has. Previously, the Company had a combined mdwq for all of the

Equitrans storage that equals 227,877 dth/day. The new storage contracts provide a combined mdwq that equals 187,546 dth/day. Therefore, the storage deliverability has decreased by 40,331 dth/day (227,877 - 187,546).

Q. DOES THIS DECREASE IN STORAGE DELIVERABILITY CAUSE THE COMPANY CONCERN?

A. No, it does not. The Company's 2006 design day analysis indicates that the firm capacity effective April 1, 2006 is sufficient to meet the requirements of its firm customers.

Q. WHAT IMPACT COULD THIS ADDITIONAL STORAGE HAVE TO FUTURE PURCHASED GAS COSTS?

A. I have attached to my direct testimony as Equitable Exhibit SCR-6 a schedule that identifies the potential impact to future gas costs. In my analysis I have used the combined seasonal price differential of approximately $2.83/dth that has been previously discussed. This analysis indicates that the potential savings in future gas costs could be approximately $5.5 million annually, if current market conditions persist. Over the term of these contracts the total purchased gas cost savings could approach $27.5 million.

Q. DOES THE COMPANY BELIEVE THAT IT CAN MITIGATE THE EQUITRANS GENERAL RATE INCREASE BY ACQUIRING ADDITIONAL STORAGE?

A. Absolutely. Most of the time natural gas prices are higher in the winter than they are during the summer for obvious reasons. The acquisition of additional storage affords the Company opportunities to capitalize on this differential.

Q. DOES THIS SEASONAL PRICE DIFFERENTIAL ALWAYS EXIST?

A. No. At times, the seasonal price differential can actually reverse, although this reversal typically will not happen unless winter weather becomes warmer than normal or at least warmer than the natural gas industry expected.

Q. CAN YOU EXPLAIN THIS PHENOMENON IN MORE DETAIL?

A. Prospectively, the seasonal gas price differential is always positive. In other words, natural gas prices for the next winter are always higher than the natural gas prices during the prior summer. This phenomenon is created because it is expected that there will be more demand and less supply during the winter than there is during the summer. However, if the winter is warmer than the natural gas industry expected, natural gas prices can decrease during the winter season, much like they did this year. This phenomenon is not typical and happens only occasionally. I have attached to my direct testimony as Equitable Exhibit SCR-8 a schedule that reflects the Dominion Appalachian Inside FERC Index prices for the period January 1994 through March 2006. The last column of this schedule indicates that there were only three (3) times in twelve (12) years that the actual seasonal price differential reversed.

Q. WHAT WOULD HAPPEN IF THE SEASONAL PRICE DIFFERENTIAL ACTUALLY DOES REVERSE AND WINTER GAS SUPPLIES BECOME LESS EXPENSIVE THAN THE PRIOR SUMMER GAS SUPPLIES?

A. The Company has the ability with its Equitrans storage contracts to defer storage withdrawals by up to 25% of the total storage quantity. In other words, the Company is required to withdraw only 75% of the total storage inventory during a particular winter season. The remaining 25% of storage inventory may be "rolled" or become a deferred storage withdrawal. This provision allows the Company to purchase lower cost flowing gas supplies, and if needed defer the withdrawal of the more expensive storage supplies. During the next summer injection season the Company has the ability to blend the remaining storage inventory with lower cost supplies and reduce the storage weighted average cost of gas ("wacog").

Q. ARE THERE CERTAIN DISADVANTAGES WITH MANAGING THE STORAGE WITHDRAWALS IN THIS FASHION?

A. There are no disadvantages to Equitable's firm customers if storage is managed in this fashion. Equitable's firm customers benefit because the Company is able to capitalize on the lower price environment and reduce overall gas costs. However, there is a disadvantage to the Company's if storage is managed in this fashion.

Q. WHY IS THERE A DISADVANTAGE TO THE COMPANY?

A. The costs associated with purchasing the gas supplies that are injected during the summer are initially paid for by the Company. During the winter as those supplies are withdrawn from storage, the Company is essentially reimbursed by the PGC. The Company is basically responsible for the carrying charges associated with the storage injections. If the Company decides to defer making storage withdrawals and instead purchases lower-cost replacement supplies in the spot market to benefit the PGC, the Company does not get reimbursed for the carrying charges related to inventory that is held in storage.

Q. CAN THE CUSTOMERS AND THE COMPANY BOTH BENEFIT FROM

DEFERRING STORAGE WITHDRAWALS IF THE SITUATION ARISES?

A. The Company proposes that the carrying costs associated with rolling the storage inventory be recorded as a purchased gas cost expense.

Q. IN ADDITION TO THE SEASONAL PRICE DIFFERENTIAL ARE THERE OTHER BENEFITS ASSOCIATED WITH THE NEW EQUITRANS STORAGE CONTRACTS?

A. Yes, there are. The Company's Rate Schedule 60-SS service has a tasq equal to 7,473,296 dth and a summer maximum daily injection quantity ("mdiq") equal to 74,733 dth. The Company has the ability to fill the storage in 100 days (7,473,296 / 74,733). Typically, the mdiq is developed so that storage customers fill the inventory ratably over the entire summer injection season, which comprises 214 days (April 1 through October 31). The higher mdiq associated with Rate Schedule 60-SS allows the Company to optimize storage injections during the summer and expand the seasonal price differential.

Finally, the conversion of the former Rate Schedules 10-SS and 30-SS to Rate Schedule 60-SS eliminates the impact of Equitrans' peaking storage ratchets. Essentially, the Rate Schedule 60-SS storage service is more reliable during the late winter season.

Q. WERE OTHER PARTIES AFFORDED THE OPPORTUNITY TO PROVIDE CAPACITY ALTERNATIVES PURSUANT TO SECTION 2204(e)(1) OF THE PUBLIC UTILITY CODE PRIOR TO THE COMPANY ENTERING INTO THESE CONTRACTS WITH EQUITRANS?

A. Yes. The Company has a notice posted on its corporate website requesting proposals for firm replacement capacity. This notice was presented to encourage interested parties to submit capacity alternatives if any existed.

Q. DID THE COMPANY RECEIVE COMMENTS OR PROPOSALS FOR ALTERNATIVE CAPACITY?

A. No. To date, Equitable has not received any replacement proposals, which has been the case with all capacity postings since the enactment of Section 2204 of the Public Utility Code.

Q. PLEASE DESCRIBE THE DOMINION FIRM TRANSPORTATION AND FIRM STORAGE CONTRACTS.

A. Equitable has two (2) firm storage contracts with Dominion, identified as GSS-300159 and GSS-300135. Contract GSS-300159 has a total annual storage quantity equal to 1,350,000 dth and a maximum daily withdrawal quantity equal to 27,000 dth/day. Contract GSS-300135 has a total annual storage quantity equal to 1,750,000 dth and a maximum daily withdrawal quantity equal to 35,000 dth/day.

In addition to the firm storage contracts, Equitable has two (2) firm transportation contracts with Dominion. These contracts are utilized in conjunction with the storage contracts to effectuate the withdrawals and injections. Contract FTGSS-700082 has an annual transportation quantity equal to 4,077,000 dth and a maximum daily transportation quantity equal to 27,000 dth/day. Contract FTGSS-700061 has an annual transportation quantity equal to 5,285,000 dth and a maximum daily transportation quantity equal to 35,000 dth/day.

Contracts GSS-300159 and FTGSS-700082 have been extended and expire March 31, 2011. Contracts GSS-300135 and FTGSS-700061 have also been extended and expire March 31, 2012. Please refer to Equitable Exhibit SCR-1 for a summary of these contracts.

Q. WHY DID EQUITABLE ELECT TO EXTEND THESE CONTRACTS?

A. There are operational and economic benefits associated with extending these contracts. First of all, this firm storage and firm transportation capacity is currently utilized to help satisfy Equitable's peak demand requirements. In addition to the operational flexibility, these storage assets can provide significant economic benefits, e.g., reductions in purchased gas costs. Again, the reductions in purchased gas costs occur because the Company has the ability to inject lower-cost supplies during the summer injection season and withdraw the same gas during the winter season when prices are typically much higher.

Q. ASIDE FROM THE SEASONAL DIFFERENTIAL, ARE THERE OTHER BENEFITS ASSOCIATED WITH THE EXTENSION OF THE DOMINION CONTRACTS?

A. Yes, there are. Dominion recently had a settlement at FERC, at Docket Nos. RP97-406, RP-00-15, RP00-344 and RP00-632, that reduces Dominion's rates for its transportation services and the fuel retention level for its storage services, and establishes a five-year moratorium on further transportation and storage changes. The annual gas cost savings resulting from this settlement are approximately $250,000, and have been appropriately reflected in this year's filing. The calculation of these savings is identified in Equitable Exhibit SCR-9.

Another significant benefit to PGC customers involves the utilization of the primary delivery points associated with contracts GSS-300135 and FTGSS-700061. Historically, Equitable has been able to create additional value by monetizing the value between these different delivery locations. Specifically, one of the delivery locations contained in the agreement (Leidy) is more valuable than the other delivery locations (Pratt Farm or Mars Crider). For the past several years, Equitable has been able to capture this value and ultimately reduce purchased gas costs for its customers.

Q. DID THE COMPANY ENTER INTO A STORAGE MANAGEMENT ARRANGEMENT THIS PAST WINTER IN AN ATTEMPT TO MONETIZE THIS VALUE?

A. No. The Company cancelled the storage management arrangement it previously had because of the opposition encountered during last year's proceeding.

Q. WAS THE COMPANY ABLE TO MONETIZE ANY OF THE VALUE ASSOCIATED WITH THESE DOMINION CONTRACTS?

A. Yes. The Company pursued a capacity release transaction for the transportation contract only. The Company did not release the storage contract. The transportation capacity release was effective for the period November 2005 through March 31, 2006.

Q. HOW MUCH VALUE WAS THE COMPANY ABLE TO MONETIZE?

A. The Company released the transportation capacity associated with contract FTGSS-700061 at maximum rates ($4.4230/dth). As usual, this capacity release was subject to recall. The total value for this capacity release arrangement was equal to approximately $775,000 (35,000 dth x $4.4230 x 5 months).

Q. WAS THIS REFLECTED IN THE COMPANY'S CURRENT FILING?

A. The Company's filing contains a capacity release credit to purchased gas costs for approximately $581,000.

Q. WHY WASN'T THE ENTIRE VALUE REFLECTED AS A CREDIT?

A. The Company reflected 75% of the total value as a credit. This is consistent with the Commission's Order related to PBR Design No. 1 from last year's proceeding. The Company retained the other 25%, or approximately $194,000.

Q. CAN YOU SUMMARIZE ALL OF THE BENEFITS ASSOCIATED WITH THE EXTENSION OF THE DOMINION CONTRACTS?

Attached to my direct testimony as Equitable Exhibit SCR-10, is a schedule that identifies the approximate annual gas cost savings associated with the extension of these contracts. Based upon current market conditions, the value or potential gas cost savings associated with extending these contracts is over $6 million annually. During the remaining term of these contracts, the value or potential gas cost savings could possibly exceed $30 million ($6 million x 5 years).

Q. WHY DID THE COMPANY ELECT TO EXTEND THE CONTRACTS 5 YEARS?

A. The Company's firm transportation contract on Texas Eastern expires October 31, 2012. The Company elected to extend the Dominion contracts and renew the Equitrans contract for an additional five (5) years so that everything expires at approximately the same time.

Q. WERE OTHER PARTIES AFFORDED THE OPPORTUNITY TO PROVIDE

CAPACITY ALTERNATIVES PURSUANT TO SECTION 2204(e)(1) OF THE PUBLIC UTILITY CODE PRIOR TO THE COMPANY ENTERING INTO THESE RENEWED CONTRACTS WITH DOMINION?

A. Yes. As I mentioned previously, the Company has a notice on its website requesting proposals for firm replacement capacity.

Q. DID THE COMPANY RECEIVE COMMENTS OR PROPOSALS FOR ALTERNATIVE CAPACITY?

A. No. To date, Equitable has not received any replacement capacity proposals.

PBR DESIGN NO. 1 – CREDIT FOR OTHER CAPACITY REVENUES

Q. PLEASE DESCRIBE THE COMPANY'S PBR DESIGN NO. 1 – CREDIT FOR OTHER CAPACITY REVENUES.

A. In Equitable's 2001 Section 1307(f) proceeding at Docket No. R-00016132, the Commission approved a guaranteed credit and performance-based incentive which rewarded Equitable if it efficiently managed its capacity release and off-system sales activity. Under this incentive plan, Equitable agreed to provide a guaranteed annual credit of $1.2 million to PGC customers for the two-year period beginning October 1, 2001 and ending September 30, 2003. The Company increased the annual credit during the next several years to a level that reached $1.75 million for the PGC period October 1, 2004 through September 30, 2005.

Q. HAS THE COMPANY REFLECTED THIS CREDIT IN THE CURRENT FILING?

A. Yes, it has. However, the credits have changed for the period beginning October

1, 2005.

Q. WHY HAVE THE CREDITS CHANGED FOR THE PERIOD BEGINNING OCTOBER 1, 2005?

A. The Commission's Order in last year's Section 1307(f) Proceeding directed Equitable to credit the PGC 75% of the revenues attributable to all exchange transactions, off-system sales, capacity release, and any future energy management revenues for the application period October 1, 2005 through September 30, 2006.

Q. WHAT ARE THE CREDITS FOR THE PERIOD BEGINNING OCTOBER 1, 2006?

A. At this time, the Company is not sure what the credits would be for the period beginning October 1, 2006. The Commission's Order from last year did not address this particular period.

Q. DOES THE COMPANY HAVE A PROPOSAL WITH RESPECT TO PBR DESIGN NO. 1?

A. At this time, we are not making a specific recommendation on how the performance-based initiative would be structured. We hope that it will evolve in settlement discussions with the parties. The Company believes that an appropriately designed performance-based mechanism, such as PBR Design No. 1, inspires superior portfolio management. It also creates an atmosphere and the appropriate incentives to establish more innovative approaches to capacity utilization. With a further extended PBR, the Company may, moreover, be able to extract higher values for certain transactions because it will have the ability to enter into longer-term arrangements. The Company's preference, however, is to establish a ceiling so that all revenues above that ceiling are retained by the Company.

DISCOUNTING OF FUEL RETENTION CHARGES

Q. WHAT HAS THE COMMISSION DETERMINED WITH RESPECT TO DISCOUNTING AND WAIVING TARIFF RULES OR RATES?

A. Equitable Witness John Quinn discusses in detail the decision reached by the Commission in Docket No. R-00050272 related to discounting and waiving tariff rates or rules. My Direct Testimony will only address the issue regarding fuel retention discounts.

Q. DOES EQUITABLE DISCOUNT OR WAIVE THE FUEL RETENTION CHARGES?

A. Occasionally, Equitable has discounted or waived the fuel retention charge for certain transportation customers. Equitable Witness John Quinn identifies, in Exhibit No. JMQ-1, the seven (7) different transportation customers that have a fuel retention rate that is different from the Company's system average rate of 5%.

Q. SHOULD THESE TRANSPORTATION CUSTOMERS BE ASSESSED A FUEL RETENTION CHARGE THAT IS EQUAL TO THE COMPANY'S SYSTEM AVERAGE RATE OF 5%?

A. No. All of the customers identified in Equitable Exhibit JMQ-1 contain temperature and pressure compensated meters. On the other hand, the Company's distribution system's average retainage rate of 5% contains some component that is attributed to temperate and pressure compensation.

Q. CAN YOU IDENTIFY THE COMPONENT ASSOCIATED WITH TEMPERATURE

AND PRESSURE COMPENSATION THAT IS CONTAINED WITHIN THE COMPANY'S SYSTEM AVERAGE RATE OF 5%?

A. Not specifically. Several studies conducted, including one by Pacific Gas and Electric Company in May 1990, and Southern California Gas Company in 1992, concluded that the gas temperature in residential or small meters tends to follow the ambient temperature. Equitable applied this methodology when it conducted its last lost and unaccounted for gas ("LUF") study. During that study, the percentage that was associated with temperature compensation was nearly 40%. This percentage will change as the ambient temperature changes.

As far as pressure compensation goes, Equitable assumes that the metered gas pressure is a constant 8 ounces or 0.5 psig for those residential and small commercial customers who are served by district regulators on the low-pressure system. For those customers that are served on an intermediate-pressure or high-pressure system, service regulators would be required. These service regulators are also set at a normal operating pressure of 0.5 psig. Any difference that occurs between the actual and the assumed pressure would have a direct impact on the metered gas volume and also would contribute to the total LUF volume. During the Company's last LUF study, the percentage that was associated with pressure compensation was approximately 18%.

In summary, over 50% of Equitable's total distribution system average lost and unaccounted for gas can be attributed to a lack of temperature and pressure compensated meters.

Q. WHAT DOES THE COMPANY SUGGEST THE RETAINAGE RATE SHOULD BE

FOR THOSE TRANSPORTATION CUSTOMERS THAT HAVE TEMPERATURE AND PRESSURE COMPENSATED METERS?

A. The Company believes the appropriate retainage rate for these transportation customers with temperature and pressure compensated meters should be 2.5% (0.50 x 5%).

Q. ARE THERE OTHER CONSIDERATIONS ASSOCIATED WITH EQUITABLE EXHIBIT JMQ-1 THAT INVOLVES THE RETAINAGE RATE?

A. Yes. The negotiated retainage rate for these customers includes an appropriate adjustment to the retainage factor since all of these customers have temperature and pressure compensated meters. Therefore, the remaining retainage factor should consist of the expected line loss and any potential measurement error.

Q. DOES THE COMPANY HAVE AN ANALYSIS THAT IDENTIFIES THE EXPECTED LINE LOSS OR THE POTENTIAL MEASUREMENT ERROR FOR THESE CUSTOMERS?

A. Not for all of them. I will specifically address the operating conditions, including measurement, for Customers 2, 4 and 7 that are identified in Equitable Exhibit JMQ-1.

Q. WHAT ARE THE OPERATING CONDITIONS ASSOCIATED WITH THESE THREE CUSTOMERS?

A. Customers 4 and 7 are served directly from distinct distribution facilities that are connected to an interstate pipeline. The distribution facilities consist of welded, steel pipe that is cathodically protected. These facilities were installed within the past five years. Customer 2, which is in the steel-making industry, is served directly from a high-pressure transmission facility that is also directly connected to an interstate pipeline. These facilities were installed in 1978 and are also cathodically protected. All of these facilities operate at high-pressures and are monitored on a regular basis for leakage. Since they are newer facilities and were pressure-tested prior to being placed in service, the Company has assumed these facilities do not have any line loss. Therefore, the only contribution to system LUF would be potential measurement error.

Q. CAN YOU DESCRIBE THIS POTENTIAL MEASUREMENT ERROR?

A. The potential measurement error is simply the difference between the actual volumes that physically go through the meter and the volumes that are recorded by the meter. In other words, it is the difference between the meter reads and the actual deliveries. The industry refers to this phenomenon as fast or slow meters.

Q. CAN THE POTENTIAL MEASUREMENT ERROR BE SIGNIFICANT?

A. Not for these large volume transportation customers.

Q. WHY IS THE POTENTIAL MEASUREMENT ERROR NOT SIGNIFICANT FOR THESE CUSTOMERS?

A. These customers represent some of the largest transportation customers on the Company's system. As such, the Company installs the most accurate measurement equipment that is available and monitors the equipment on a regular basis. Calibration tests are conducted frequently to ensure the measurement is accurate. During the Company's last LUF study the effect of fast and slow meters was determined to be 0.24%.

Q. DOES THE COMPANY BELIEVE IT IS ADEQUATELY REFLECTING THE APPROPRIATE LEVEL OF RETAINAGE FOR THESE CUSTOMERS?

A. Based upon my explanations above, the Company believes that the negotiated retainage rates reflected in Equitable Exhibit JMQ-1 adequately compensates the Company for the retainage levels that are actually experienced.

EIA GAS STORAGE REPORT

Q. IN THE 2005 SECTION 1307(F) PROCEEDING, THE OSBA RAISED AN ISSUE IN CONNECTION WITH AN ERROR THAT OCCURRED IN THE REPORTING OF GAS WITHDRAWALS BY DOMINION TO THE ENERGY INFORMATION ADMINISTRATION AND THE COMPANY AGREED IN SETTLEMENT TO REPORT ON THE STATUS OF ANY CLASS ACTION RELATED TO THE STORAGE REPORT ERROR. IS EQUITABLE AWARE OF ANY CLASS ACTION PROCEEDING RELATED TO THE STORAGE REPORT ERROR AND, IF SO, WHAT IS THE STATUS OF THE PROCEEDING?

A. Equitable is aware of a class action proceeding related to the storage report error. I have been advised by counsel that a class action complaint was filed in the circuit court of Kanawha County, West Virginia, on or about February 16, 2005, and captioned Betsy J. Jacquet, Patricia E. Kuzara, and others similarly situated v. Dominion Transmission, Inc., Dominion Resources, Inc., Dominion Virginia Power, Dominion North Carolina Power, Civil Action No. 05-C-351. The defendants removed the case to federal district court in July of 2005. On August 1, 2005, the plaintiffs filed a motion to remand the case back to the West Virginia State Court. As of the filing of my testimony, the plaintiffs' motion has not been decided by the federal court.

Q. WHAT IS THE COMPANY DOING IN REGARD TO THE ACTION?

A. The Company is continuing to monitor the proceeding. I have been advised by counsel that unless a more appropriate action is instituted in the meantime the Company will seek class action intervention upon final determination of the proper venue.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ATTACHMENT A

Sections of the 1307(f) Filing S. C. Rafferty is sponsoring:

Item 53.64 (a), Section I

Part B: Sheet 1 of 8, lines 11-16
Part B: Sheet 2 of 8
Part B: Sheet 3 of 8
Part B: Sheet 4 of 8
Part B: Sheet 5 of 8
Part B: Sheet 6 of 8
Part B: Sheet 7 of 8
Part B: Sheet 8 of 8

Part C: Sheet 4 of 7, lines 11-16
Part C: Sheet 5 of 7
Part C: Sheet 6 of 7
Part C: Sheet 7 of 7

Item 53.64 (c) (1)
Item 53.64 (c) (3)
Item 53.64 (c) (5)
Item 53.64 (c) (6)
Item 53.64 (c) (7)
Item 53.64 (c) (10)
Item 53.64 (c) (12)
Item 53.64 (c) (13)
Item 53.64 (c) (14)
Item 53.65 (1) through (5)

EQUITABLE GAS COMPANY

PROPOSED 2006 GAS SUPPLY HEDGING PROGRAM

Objective:

The objective of Equitable's 2006 Hedging Program ("Program") is to define the appropriate procedures to be used by Equitable for hedging a portion of its future cost of gas supplies. Equitable proposes to hedge up to an agreed upon portion of its annual projected purchases using primarily NYMEX futures contracts and fixed-price physical purchases. The implementation of this Program will reduce the exposure that Equitable's customers have regarding gas price volatility. This Program may not reduce the gas price that Equitable's customers ultimately pay. Any gas cost increases and/or reductions that occur as a result of Equitable implementing this Program will be recovered in the quarterly gas cost filings and are subject to review during the annual 1307(f) proceedings. Equitable anticipates using a combination of NYMEX futures contracts and fixed-price physical purchases for its Appalachian purchases as well as its interstate pipeline purchases. Each of these categories and corresponding procedures are explained in more detail below. Equitable will not proceed with this Program unless there is a consensus among the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA") and the Office of Trial Staff ("OTS"), collectively referred to as the "Parties", that this Program is appropriate.

Appalachian Supplies:

Background:
Equitable purchases a significant portion of its gas supplies from numerous Appalachian Producers. These Appalachian Producers can deliver supplies directly into Equitable's distribution system or into an interstate pipeline that traverses the Appalachian Basin, e.g., Equitrans, LP or Dominion Transmission. The Appalachian supplies that originate on these interstate pipeline(s) are ultimately delivered into Equitable's distribution system.

Equitable has a local Appalachian gas purchase strategy which consists of various pricing mechanisms, ranging from fixed pricing options to several different index pricing options. This strategy seeks to encourage the development of new, incremental supplies while also attempting to reduce price volatility and operational uncertainties. Equitable utilizes short-term gas purchase agreements, long-term gas purchase agreements and existing life- of-the-well gas purchase agreements to provide a stable, long-term source of reliable supply. Historically, Equitable has permitted various producers the opportunity to "lock-in" or fix the price of gas based on current market conditions. These fixed-price purchases are aggregated with other index or market-based purchases during the actual month of production. These fixed-price purchases will generally be above or below current market conditions depending upon the previously agreed to price.

Hedging Procedures:
Equitable will continue to permit Appalachian Producers the opportunity to "lock-in" or fix the price of gas based on current market conditions. Appalachian Producers that elect this option must have at least 2,500 MMBtu per month of production. Equitable will only "lock-in" prices in 2,500 MMBtu increments. (Equitable will calculate the volumes eligible for "lock-in" at 85% of the lowest 12-months of actual production volumes. The resulting amount must be equal to or greater than 2,500 MMBtu or the Producer is not eligible to "lock-in"). The difference between the "locked-in" or fixed-priced volume and the actual produced volume during a month will be paid based upon the default price in place. This default price is typically

index-related or market-based. Appalachian Producers must "lock-in" prices for an annual or seasonal term. The seasonal terms are defined as April through October and/or November through March. In the event a Producer does not have enough production to offset the previously "locked-in" volumes, that Producer will be responsible for the difference between the "locked-in" price and the current market price. In the event the current market price is less expensive than the previously "locked-in" price, there will be <u>no</u> refund to the Producer. (A financial gain will occur on the NYMEX hedges that will be credited to PGC costs).

At the same time a Producer elects to "lock-in" the gas price for a specified term, Equitable will sell corresponding NYMEX contracts for the identical volume and term. When the NYMEX contracts ultimately settle, a financial gain or loss will occur. The financial gain or loss, when added to the original "lock-in" price will result in a price that is representative of current "market" conditions.

In the event a Producer elects to "lock-in" the gas price for a specified term, Equitable will withhold any "margining" expense incurred as a result of executing the financial hedges. Margining expense is defined as the money that buyers and sellers of futures, i.e., Equitable, must put up with the clearinghouse to assure performance on the contracts. Equitable will also assess the Producers a volumetric charge for administration of this Program.

Equitable will report all hedging activity associated with Appalachian Producers separately from its hedging activity associated with interstate pipeline suppliers. Gains as well as losses will flow through the PGA mechanism.

<u>Interstate Pipeline Supplies:</u>

<u>Background:</u>
The Appalachian supplies are used in conjunction with the interstate spot market to achieve a level of reliability necessary to meet Equitable's customer demand. Equitable continues to use the interstate spot market, on an economic basis, to either satisfy immediate demand requirements or for storage injection purposes. *Currently, Equitable purchases interstate supplies for its ratepayers on Texas Eastern* ("TETCO"), Dominion Transmission ("DTI") and Equitrans, LP ("EQT").

<u>Hedging Procedures:</u>
Equitable will prepare annual projections of requirements and supplies. These projections will be based on normal weather occurrence. Equitable will review the projections on a quarterly basis and add/delete respective months and also make adjustments due to more recent information. Please refer to Attachment "A" for the annual projections of PGC requirements and supplies.

Equitable's Program will attempt to fix the price of gas on an amount that is between 25% and 50% of the projected monthly purchases during the summer (April through October), *including* volumes required for storage injections. During the winter (November through March), Equitable's Program will attempt to fix the price of gas on an amount that is between 10% and 20% of the projected monthly purchases, *excluding* volumes withdrawn from storage. [The hedge volumes are significantly reduced during the winter since the Company has a considerable amount of gas that comes from storage. The cost of these gas supplies are developed when they are originally injected into storage during the summer. Since the price is fixed when the storage supplies are withdrawn during the winter, these supplies are essentially hedged.]

Equitable will continue to use the Planalytics' Weathernomics Gas Buyer™, to assist in some of the interstate pipeline natural gas purchases more than one month in advance of the month of flow. (Planalytics' Weathernomics Gas Buyer™ is a web-delivered tool that aids in natural gas price analysis and enables users to better identify weather-driven changes in gas prices up to one year into the future). Equitable will utilize the Planalytics' Weathernomics Gas Buyer™ exclusively for the recommended minimum volumes (25% during the summer and 10% during the winter). These volumes are identified on Attachment "A" as the Minimum Volumes (Dth) – Planalytics. The annual license and maintenance fees imposed by Planalytics' Weathernomics Gas Buyer™ will continue to be recovered through the PGA mechanism. Gains as well as losses will flow through the PGA mechanism for any purchases that are made using the Planalytics' Weathernomics Gas Buyer™.

For those interstate pipeline purchases not made by using the Planalytics' Weathernomics Gas Buyer™ recommendations, Equitable will continue to use the expertise within its Gas Acquisition & Management Department. Equitable's Gas Acquisition & Management Department is responsible for all gas supply and planning functions. This department is adequately staffed with qualified and well-trained personnel who receive regular updates on conforming with the Company's least cost purchasing policy. In addition to their industry experience, personnel responsible for gas supply and planning attend seminars, conferences and short courses that address supply strategies and methodologies. Additionally, they communicate continuously with gas suppliers, producers, marketers and interstate pipeline representatives in matters pertaining to Equitable's fuel procurement policy. Furthermore, these personnel receive frequent updates of current trends and new developments within the natural gas industry. The volumes that can be hedged by these other resources are the recommended maximum volumes (50% during the summer and 20% during the winter). These volumes are identified on Attachment "A" as the Maximum Volumes (Dth) – Other.

Gas prices for interstate pipeline purchases can be hedged through the purchase of either:

(1) New York Mercantile Exchange ("NYMEX") natural gas futures contracts, plus; fixed basis differentials from the Henry Hub to DTI South Point; or,
(2) Fixed-price supplies, in either the Gulf Coast area or the market area, e.g., DTI South Point.

Gains as well as losses resulting from hedging interstate pipeline purchases will flow through the PGA mechanism.

Other Considerations:

In the event any Party desires to make modifications to this Program, the Parties agree to meet and determine what change(s), if any, are necessary. There must be unanimous support among the Parties for any recommended change(s) to become effective.

At the end of successive three-year periods, beginning October 1, 2006, the Parties shall review the hedging program structure and results and, if mutually agreed upon, the Program shall be extended in its current or a revised form.

ATTACHMENT "A"

Proposed Hedging Schedule for Interstate Pipeline Purchases

Summary of Estimated Annual PGC Sales and Supply Requirements

Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
PGC Sales - Mcf													
Residential	1,079,353	2,108,612	3,222,205	3,887,113	3,382,608	2,736,776	1,639,446	669,742	354,297	363,505	362,726	402,456	20,208,839
Small Commercial	135,971	226,576	342,371	424,988	368,697	313,552	190,321	96,037	63,274	60,993	65,152	68,803	2,356,735
Small Industrial	628	1,080	1,606	1,979	1,739	1,428	903	443	305	270	265	307	10,953
Large Commercial	93,228	154,657	231,051	287,905	250,545	215,531	131,397	69,089	47,742	45,504	47,784	50,895	1,625,328
Large Industrial	2,825	4,365	6,607	7,854	6,897	6,000	3,899	2,163	1,760	1,628	1,683	1,564	47,245
Total PGC Sales	1,312,005	2,495,290	3,803,840	4,609,839	4,010,486	3,273,287	1,965,966	837,474	467,378	471,900	477,610	524,025	24,249,100
Company Use	4,396	8,361	12,746	15,446	13,438	10,968	6,587	2,806	1,566	1,581	1,600	1,756	81,251
UFG	69,284	131,771	200,873	243,436	211,785	172,856	103,819	44,225	24,681	24,920	25,222	27,673	1,280,545
Total Demand - Mcf	1,385,685	2,635,422	4,017,459	4,868,721	4,235,709	3,457,111	2,076,372	884,505	493,625	498,401	504,432	553,454	25,610,896
BTU Conversion	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	-
Total Demand - Dth	1,468,826	2,793,547	4,258,507	5,160,844	4,489,852	3,664,538	2,200,954	937,575	523,243	528,305	534,698	586,661	27,147,550
PGC Purchases - Dth													
Southwest Purchases	3,669,090	87,152	99,115	105,112	106,705	95,101	2,915,797	2,462,892	2,375,560	2,363,622	2,370,015	2,438,978	19,089,138
Appalachian - Direct	209,250	202,500	209,250	209,250	189,000	209,250	202,500	209,250	127,500	131,750	131,750	127,500	2,158,750
Appalachian - Transport	627,750	607,500	627,750	627,750	567,000	627,750	607,500	627,750	382,500	395,250	395,250	382,500	6,476,250
DOM Storage	(558,000)	379,750	651,000	821,500	708,970	538,780	(372,000)	(434,000)	(434,000)	(434,000)	(434,000)	(434,000)	0
DOM Storage Fuel	(14,285)						(9,523)	(11,110)	(11,110)	(11,110)	(11,110)	(11,110)	(79,360)
DOM Transport Fuel	(17,455)	(11,582)	(19,856)	(25,056)	(21,624)	(16,433)	(11,636)	(13,576)	(13,576)	(13,576)	(13,576)	(13,576)	(191,520)
EQT Storage	(2,392,498)	1,528,227	2,691,247	3,422,288	2,939,801	2,210,089	(1,094,998)	(1,860,831)	(1,860,831)	(1,860,831)	(1,860,831)	(1,860,831)	0
EQT Storage Fuel	(55,027)						(36,685)	(42,799)	(42,799)	(42,799)	(42,799)	(42,799)	(305,708)
Total PGC Purchases	1,468,826	2,793,547	4,258,507	5,160,844	4,489,852	3,664,538	2,200,954	937,575	523,243	528,305	534,698	586,661	27,147,550

Hedging Strategies:

Summer (Min = 25%; Max = 50%); Winter (Min = 10%; Max = 20%)

Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
Minimum Percentage	25%	10%	10%	10%	10%	10%	25%	25%	25%	25%	25%	25%	
Maximum Percentage	50%	20%	20%	20%	20%	20%	50%	50%	50%	50%	50%	50%	
Total Interstate Purchases (Southwest Purchases + Appalachian - Transport)	4,296,840	694,652	726,865	732,862	673,705	722,851	3,523,297	3,090,642	2,758,060	2,758,872	2,765,265	2,821,478	25,565,388
Minimum Volumes (Dth) - Planalytics	1,074,210	69,465	72,687	73,286	67,370	72,285	880,824	772,660	689,515	689,718	691,316	705,369	
Maximum Volumes (Dth) - Other	2,148,420	138,930	145,373	146,572	134,741	144,570	1,761,648	1,545,321	1,379,030	1,379,436	1,382,632	1,410,739	

Attachment B

Equitable Exhibit SCR-1

Equitable Gas Company
Gas Acquisition & Management Department
Summary of Transportation & Storage Agreements

PENNSYLVANIA

Equitrans Storage Agreements:

Agreement Number	Transport Agreement	MDQ Injection	MDQ Withdrawal	TASQ	Termination Date
092 (10SS)	**FTS-049**	3,957	79,144	791,440	31-Mar-2006
050 (30SS)	**FTS-049**	12,639	84,260	2,527,826	31-Mar-2006
090 (60SS)	**FTS-049**	7,342	24,473	1,468,380	31-Mar-2006
356 (115SS)	**FTS-357**	20,909	40,000	4,181,818	31-Mar-2006
Totals		44,847	227,877	8,969,464	

Equitrans Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Termination Date
FTS - 357	**Storage - (115SS - 356)**	20,909	40,000	31-Mar-2006
FTS - 031	**Appalachian**	25,000	25,000	31-Mar-2006
FTS - 098	**Interstate pipeline transport**	166,000	166,000	31-Mar-2006
FTS - 049	**Storage - (60SS, 30SS, 10SS)**	23,938	187,877	31-Mar-2006
NN - 099	**No-Notice service**	39,376	94,742	31-Mar-2006
Totals		275,223	513,619	

TOTAL EQUITRANS ENTITLEMENTS			513,619	

Dominion Storage/Transportation Agreements:

Agreement Number	Transport Agreement	MDQ Injection	MDQ Withdrawal	TASQ	Termination Date
GSS-300135	**FTGSS-700061**	8,178	35,000	1,750,000	31-Mar-2012
GSS-300159	**FTGSS-700082**	6,308	27,000	1,350,000	31-Mar-2011
			62,000	3,100,000	

Texas Eastern Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Termination Date
FT-800342	**Interstate pipeline transport**	109,207	109,207	31-Oct-2012

Equitable Gas Company

Gas Acquisition & Management Department
Summary of Equitrans' and CIPCO's Transportation & Storage Agreements

Equitable Exhibit SCR-2

PENNSYLVANIA

Equitrans Storage Agreements:

Agreement Number	Transport Agreement	Gross Into Equitrans	Delivery to 90001 (boundary) @ 2.75% shrink	MDQ Injection @ 0.490% shrink	MDQ Withdrawal	TASQ	Injection Charges $0.0089	Withdrawal Charges $0.0089	Storage Demand Charges $1.3887	Storage Space Charges $0.0265	ANNUAL CHARGES
092 (10SS)	FTS-049	4,088	3,976	3,957	79,144	791,440	$7,043.82	$7,043.82	$109,907.27	$20,973.16	
050 (30SS)	FTS-049	13,060	12,701	12,639	84,260	2,527,826	$22,497.65	$22,497.65	$117,011.86	$66,987.39	
090 (60SS)	FTS-049	7,587	7,378	7,342	24,473	1,468,380	$13,068.58	$13,068.58	$33,985.66	$38,912.07	
356 (115SS)	FTS-357	21,606	21,012	20,909	40,000	4,181,818	$37,218.18	$37,218.18	$55,548.00	$110,818.18	$4,058,298.00 DEMAND
080 (SS-3)	FTS-028	8,456	8,223	8,183	15,654	1,636,539	$14,565.20	$14,565.20	$21,738.71	$43,368.28	$3,372,708.95 SPACE
Totals		54,797	53,290	53,030	243,531	10,606,003	$94,393.43	$94,393.43	$338,191.50	$281,059.08	$7,431,006.95 SUB-TOTAL STORAGE

Equitrans Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Discounted Summer Billing MDQ	Discounted Winter Billing MDQ	TASQ	Variable Commodity charges $0.0171	Winter Demand Charges (monthly) $5.7625	Summer Demand Charges (monthly) $5.0087	ANNUAL CHARGES
FTS - 028	Storage - (SS3 - 078)	8,183	15,654	7,647	10,838	1,636,539	$27,984.82	$62,453.98	$38,301.53	$312,269.88 Winter Demand $268,110.70 Summer Demand
FTS - 357	Storage - (115SS - 356)	21,012	40,000			4,181,818	$71,509.09	$230,500.00	$105,242.80	$1,152,500.00 Winter Demand $736,699.63 Summer Demand
FTS - 031	Appalachian	25,000	25,000					$144,062.50	$125,217.50	$720,312.50 Winter Demand $876,522.50 Summer Demand
FTS - 049	Storage - (10SS, 30SS, 60SS)	24,056	187,877		81,839	4,787,646	$81,868.75	$471,597.24	$120,469.29	$2,357,086.19 Winter Demand $843,425.01 Summer Demand
FTS - 098	Interstate pipeline transport	166,000	166,000					$956,575.00	$831,444.20	$4,782,875.00 Winter Demand
								$8.3395	$7.5857	$5,820,109.40 Summer Demand
NN - 099	No-Notice service	39,376	94,742					$790,100.91	$298,694.52	$3,950,504.55 Winter Demand $2,090,861.66 Summer Demand
Totals		283,627	529,273			10,606,003		$2,655,297.96	$1,519,397.43	$23,912,177.01 SUB-TOTAL TRANSPORTATION
										$31,343,183.96 TOTAL EQUITRANS

Carnegie ("CIPCO") Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Discounted Summer Billing MDQ	Discounted Winter Billing MDQ	TASQ	Variable Commodity charges $0.0055	Winter Demand Charges (monthly) $6.8215	Summer Demand Charges (monthly) $6.8215	ANNUAL CHARGES
FTS	Interstate pipeline transport	11,910	11,910					$81,244.07	$81,244.07	$974,928.78 TOTAL CIPCO

$32,318,112.74	AFFILIATE TOTAL

Equitable Gas Company

Gas Acquisition & Management Department
Summary of Equitrans' and CIPCO's Transportation & Storage Agreements

PENNSYLVANIA

Equitable Exhibit SCR-3

Equitrans Storage Agreements:

Agreement Number	Transport Agreement	Gross into Equitrans	Delivery to 90001 (boundary) @ 2.75% shrink	MDQ Injection @ 0.490% shrink	MDQ Withdrawal	TASQ	Injection Charges $0.0155	Withdrawal Charges $0.0155	Storage Demand Charges $1.8289	Storage Space Charges $0.0353	ANNUAL CHARGES
092 (10SS)	FTS-049	4,088	3,976	3,957	79,144	791,440	$12,267.32	$12,267.32	$144,746.46	$27,937.83	
050 (30SS)	FTS-049	13,060	12,701	12,639	84,260	2,527,826	$39,181.30	$39,181.30	$154,103.11	$89,232.26	
090 (60SS)	FTS-049	7,587	7,378	7,342	24,473	1,468,380	$22,759.89	$22,759.89	$44,758.67	$51,833.81	
356 (115SS)	FTS-357	21,606	21,012	20,909	40,000	4,181,818	$64,818.18	$64,818.18	$73,156.00	$147,618.18	$5,344,726.15 DEMAND
080 (SS-3)	FTS-028	8,456	8,223	8,183	15,654	1,636,539	$25,366.35	$25,366.35	$28,629.60	$57,769.83	$4,492,702.87 SPACE
Totals		54,797	53,290	53,030	243,531	10,606,003	$164,393.05	$164,393.05	$445,393.85	$374,391.91	$9,837,429.02 SUB-TOTAL STORAGE

Equitrans Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Summer Billing MDQ	Winter Billing MDQ	TASQ	Variable Commodity charges $0.0089	Winter Demand Charges (monthly) $6.2535	Summer Demand Charges (monthly) $5.5105	ANNUAL CHARGES
FTS - 028	Storage - (SS3 - 078)	8,183	15,654	8,183	15,654	1,636,539	$14,565.20	$97,892.29	$45,092.42	$489,461.45 Winter Demand $315,646.95 Summer Demand
FTS - 357	Storage - (115SS - 356)	21,012	40,000			4,181,818	$37,218.18	$250,140.00	$115,786.63	$1,250,700.00 Winter Demand $810,506.38 Summer Demand
FTS - 031	Appalachian	25,000	25,000					$156,337.50	$137,762.50	$781,687.50 Winter Demand $964,337.50 Summer Demand
FTS - 049	Storage - (10SS, 30SS, 60SS)	24,056	187,877		187,877	4,787,646	$42,610.05	$1,174,888.82	$132,560.59	$6,874,444.10 Winter Demand $927,924.12 Summer Demand
FTS - 098	Interstate pipeline transport	166,000	166,000					$1,038,081.00	$914,743.00	$5,190,405.00 Winter Demand $6,403,201.00 Summer Demand
NN - 099	No-Notice service	39,376	94,742					$9.5587 $905,610.36	$8.8157 $347,127.00	$4,528,051.78 Winter Demand $2,429,889.02 Summer Demand
Totals		283,627	529,273			10,606,003		$3,622,959.52	$1,693,080.95	$29,960,254.79 SUB-TOTAL TRANSPORTATION
										$39,803,683.81 TOTAL EQUITRANS

Carnegie ("CIPCO") Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Discounted Summer Billing MDQ	Discounted Winter Billing MDQ	TASQ	Variable Commodity charges $0.0055	Winter Demand Charges (monthly) $1.9719	Summer Demand Charges (monthly) $1.9719	ANNUAL CHARGES
FTS	Interstate pipeline transport	11,910	11,910					$23,485.33	$23,485.33	$281,823.95 TOTAL CIPCO
										$40,085,507.76 AFFILIATE TOTAL

Pennsylvania Division

Summary of Estimated Firm Capacity Costs on Equitrans Inc.
for the Period October 2006 through September 2007

Line No.	Description	2006 October	November	December	2007 January	February	March	April	May	June	July	August	September	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	FTS Demand - Non-Storage													
1	Demand Determinant - Dth	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	2,292,000
2	Demand Rate - $/Dth	4.7451	5.3098	5.3098	5.3098	5.3098	5.3098	4.7451	4.7451	4.7451	4.7451	4.7451	4.7451	-
3	Demand Cost - $	906,314	1,014,172	1,014,172	1,014,172	1,014,172	1,014,172	906,314	906,314	906,314	906,314	906,314	906,314	11,415,058
	FTS Demand - NOFT													
4	Demand Determinant - Dth	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	954,540
5	Demand Rate - $/Dth	7.5189	8.2909	8.2909	8.2909	8.2909	8.2909	7.5189	7.5189	7.5189	7.5189	7.5189	7.5189	-
6	Demand Cost - $	598,091	659,500	659,500	659,500	659,500	659,500	598,091	598,091	598,091	598,091	598,091	598,091	7,484,137
	FTS Demand - Storage Base Load Services													
7	Demand Determinant - Dth	20,909	40,000	40,000	40,000	40,000	40,000	20,909	20,909	20,909	20,909	20,909	20,909	346,363
8	Demand Rate - $/Dth	4.7451	5.3098	5.3098	5.3098	5.3098	5.3098	4.7451	4.7451	4.7451	4.7451	4.7451	4.7451	
9	Demand Cost - $	99,215	212,392	212,392	212,392	212,392	212,392	99,215	99,215	99,215	99,215	99,215	99,215	1,756,465
	Peaking Services													
10	Demand Determinant - Dth	80,241	147,546	147,546	147,546	147,546	147,546	80,241	80,241	80,241	80,241	80,241	80,241	1,299,417
11	Demand Rate - $/Dth	4.7451	5.3098	5.3098	5.3098	5.3098	5.3098	4.7451	4.7451	4.7451	4.7451	4.7451	4.7451	
12	Demand Cost - $	380,752	783,440	783,440	783,440	783,440	783,440	380,752	380,752	380,752	380,752	380,752	380,752	6,582,484
	Storage Demand Base Load Services													
13	Capacity Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	480,000
14	Capacity Rate - $/Dth	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	-
15	Capacity Cost - $	59,796	59,796	59,796	59,796	59,796	59,796	59,796	59,796	59,796	59,796	59,796	59,796	717,552
16	Space Determinant - Dth	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	50,181,816
17	Space Rate - $/Dth	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	-
18	Space Cost - $	109,564	109,564	109,564	109,564	109,564	109,564	109,564	109,564	109,564	109,564	109,564	109,564	1,314,768
	Peaking Storage													
19	Capacity Determinant - Dth	147546	147546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	1,770,552
20	Capacity Rate - $/Dth	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	1.4949	
21	Capacity Cost - $	220,567	220,567	220,567	220,567	220,567	220,567	220,567	220,567	220,567	220,567	220,567	220,567	2,646,804
22	Space Determinant - Dth	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	102,898,020
23	Space Rate - $/Dth	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	0.0262	
24	Space Cost - $	224,661	224,661	224,661	224,661	224,661	224,661	224,661	224,661	224,661	224,661	224,661	224,661	2,695,932
25	Total Storage Demand Cost	614,588	614,588	614,588	614,588	614,588	614,588	614,588	614,588	614,588	614,588	614,588	614,588	7,375,056
26	Total Equitrans Demand Costs	2,598,960	3,284,092	3,284,092	3,284,092	3,284,092	3,284,092	2,598,960	2,598,960	2,598,960	2,598,960	2,598,960	2,598,960	34,613,180

Equitable Exhibit SCR-4

Equitable Exhibit SCR-5

Equitable Gas Company
Gas Acquisition & Management Department
Summary of Transportation & Storage Agreements

PENNSYLVANIA

Equitrans Storage Agreements:

Agreement Number	Transport Agreement	MDQ Injection	MDQ Withdrawal	TASQ	Termination Date
090 (60SS)	**FTS - 049**	74,733	137,010	7,473,296	31-Mar-2011
356 (115SS)	**FTS - 357**	26,417	50,536	5,283,357	31-Mar-2011
Totals		101,150	187,546	12,756,653	

Equitrans Transportation Agreements:

Agreement Number	Description	MDQ (Summer)	MDQ (Winter)	Termination Date
FTS - 357	**Storage - (115SS - 356)**	27,039	50,536	31-Mar-2011
FTS - 031	**Appalachian**	25,000	25,000	31-Mar-2011
FTS - 098	**Interstate pipeline transport**	166,000	166,000	31-Mar-2011
FTS - 049	**Storage - (60SS - 090)**	76,492	137,010	31-Mar-2011
NN - 099	**No-Notice service**	79,545	79,545	31-Mar-2011
Totals				
TOTAL EQUITRANS ENTITLEMENTS		374,076	458,091	

Equitable Exhibit SCR-6

	NYMEX	basis differential	total	
Apr-06	$7.233	$0.30	$7.53	
May-06	$7.210	$0.30	$7.51	
Jun-06	$7.420	$0.30	$7.72	
Jul-06	$7.625	$0.30	$7.93	
Aug-06	$7.770	$0.30	$8.07	
Sep-06	$7.890	$0.30	$8.19	
Oct-06	$8.060	$0.30	$8.36	
	$53.208		$55.31	
average	$7.601		$7.90	/ 1
Nov-06	$9.125	$0.50	$9.63	
Dec-06	$10.065	$0.50	$10.57	
Jan-07	$10.715	$0.50	$11.22	
Feb-07	$10.710	$0.50	$11.21	
Mar-07	$10.525	$0.50	$11.03	
	$51.140		$53.64	
average	$10.228		$10.73	/ 2
seasonal differential			$2.83	/ 3 = (2 - 1)

Equitable Exhibit SCR-7

additional storage quantity	3,787,189	1 /
seasonal differential	$2.83	2 /
seasonal value	$10,717,744.87	3 / = (1 * 2)
combined unit cost for storage & transportation	$1.39	4 /
annual storage cost	$5,256,695.34	5 / = (1 * 4)
potential gas cost savings	$5,461,049.53	6 / = (3 - 5)

4 / assumes Rate Schedule 60-SS Service

mdwq	63,120
mdiq	37,872

			base	winter	annual cost
storage rates					
	demand	$1.4949			$1,132,293.77
	space	$0.0262			$1,190,692.22
transportation rates			$4.7451	$5.3098	
			$1,257,941.34	$1,675,768.01	$2,933,709.35
				total	$5,256,695.34
				unit rate	$1.39

Equitable Exhibit SCR-8

Inside FERC - Dominion Transmission - *Appalachian Index*

	January	February	March	April	May	June	July	August	September	October	November	December	average Apr - Oct	average Nov - Mar	actual seasonal *differential*
1994	$2.33	$2.75	$2.85	$2.23	$2.29	$1.99	$2.10	$1.90	$1.55	$1.50	$1.83	$1.93	$1.937	$1.780	($0.157)
1995	$1.87	$1.65	$1.62	$1.68	$1.83	$1.86	$1.62	$1.49	$1.68	$1.77	$1.97	$2.53	$1.704	$3.384	$1.680
1996	$3.80	$3.67	$4.95	$3.21	$2.43	$2.54	$2.86	$2.50	$1.94	$1.99	$3.05	$4.50	$2.496	$3.436	$0.940
1997	$4.50	$3.20	$1.93	$2.04	$2.32	$2.46	$2.31	$2.33	$2.71	$3.32	$3.59	$2.70	$2.499	$2.656	$0.157
1998	$2.44	$2.15	$2.40	$2.50	$2.46	$2.19	$2.47	$2.06	$1.79	$2.22	$2.25	$2.23	$2.241	$2.032	($0.209)
1999	$1.95	$1.95	$1.78	$2.09	$2.51	$2.35	$2.42	$2.80	$3.07	$2.73	$3.28	$2.28	$2.567	$2.758	$0.191
2000	$2.53	$2.91	$2.79	$3.06	$3.28	$4.59	$4.56	$4.02	$4.85	$5.63	$4.79	$6.39	$4.284	$6.832	$2.548
2001	$10.91	$6.68	$5.39	$5.73	$5.19	$3.95	$3.38	$3.33	$2.42	$2.02	$3.37	$2.42	$3.717	$2.674	($1.043)
2002	$2.79	$2.20	$2.59	$3.59	$3.54	$3.55	$3.47	$3.13	$3.38	$3.82	$4.43	$4.44	$3.497	$6.352	$2.855
2003	$5.33	$6.36	$11.20	$5.54	$5.60	$6.36	$5.72	$4.97	$5.21	$4.78	$4.94	$5.34	$5.454	$5.764	$0.310
2004	$6.54	$6.51	$5.49	$5.70	$6.35	$7.09	$6.47	$6.30	$5.32	$5.96	$8.04	$8.13	$6.170	$7.204	$1.034
2005	$6.58	$6.63	$6.64	$7.74	$7.11	$6.45	$7.31	$7.95	$11.14	$14.67	$14.51	$11.78	$8.910	$10.890	$1.980
2006	$11.93	$8.70	$7.53	$10.89											

Equitable Exhibit SCR-9

DOMINION STORAGE / TRANSPORTATION CONTRACTS

Current Rates:

TRANSPORTATION:

Contract No.	Rate Schedule	Determinants	Current Demand Rate	Monthly Demand
700082	FT-GSS	27,000	$5.3047	$143,226.90
700061	FT-GSS	35,000	$5.3047	$185,664.50
		62,000		$328,891.40
	winter only; annual cost (5)			$1,644,457.00

STORAGE:

Contract No.	Rate Schedule	Determinai	Current Rate	Monthly Demand	Annual Demand Costs	Annual Savings
300159	GSS	1,350,000				
300135	GSS	1,750,000				
space determinant		3,100,000	$0.0143	$44,330.00		
capacity determinant		62,000	$1.8627	$115,487.40		
				$159,817.40		
		annual cost (12)		$1,917,808.80	$3,562,265.80	

Proposed Rates:

TRANSPORTATION:

Contract No.	Rate Schedule	Determinants	Current Demand Rate	Monthly Demand
700082	FT-GSS	27,000	$4.5347	$122,436.90
700061	FT-GSS	35,000	$4.5347	$158,714.50
		62,000		$281,151.40
	winter only; annual cost (5)			$1,405,757.00

STORAGE:

Contract No.	Rate Schedule	Determinai	Current Rate	Monthly Demand	Annual Demand Costs	Annual Savings
300159	GSS	1,350,000				
300135	GSS	1,750,000				
space determinant		3,100,000	$0.0143	$44,330.00		
capacity determinant		62,000	$1.8627	$115,487.40		
				$159,817.40		
		annual cost (12)		$1,917,808.80	$3,323,565.80	($238,700.00)

Equitable Exhibit SCR-10

seasonal differential		$2.83	1 /
TASQ	GSS-300135	1,750,000	
TASQ	GSS-300159	1,350,000	
		3,100,000	2 /
	seasonal value	$8,773,000.00	3 / = (1 * 2)
	est. transportation capacity value	$750,000.00	4 /
	demand costs	$3,323,565.80	5 / refer to Exhibit SCR-9
	est. annual value	$6,199,434.20	6 / = (3 + 4 - 5)

ORIGINAL

Equitable Statement No. 4-R
Docket No. R-00061295
Witness: Stephen C. Rafferty
Date: JUN 16 2006

EQUITABLE GAS COMPANY

Prepared Rebuttal Testimony of

Stephen C. Rafferty

(Prepared June 2006)

PREPARED REBUTTAL TESTIMONY OF STEPHEN C. RAFFERTY

WITNESS BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen C. Rafferty. My business address is 225 North Shore Drive, Pittsburgh, Pennsylvania 15212.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Equitable Gas Company ("Equitable" or the "Company"), a division of Equitable Resources, Inc., as Vice-President, Utility Asset Management.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony that has been marked as Equitable Statement No. 4.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony I will respond to various contentions in the direct testimony of Office of Consumer Advocate ("OCA") witness Jerome D. Mierzwa, Office of Trial Staff ("OTS") witness Michael Gruber and NRG Energy Center Pittsburgh, LLC ("NRG") witness Timothy Merrill. Specifically, I will respond to Mr. Mierzwa's contentions that: (i) the Company's design peak day requirements are overstated by approximately 30,000 dth and that Equitable should aggressively pursue the realignment of its interstate pipeline capacity portfolio to match the design peak day requirements of its customers; (ii) the costs associated with fuel retention discounts should be recovered from all customers by increasing the Company's generally applicable fuel retention charge to 10 percent and the fuel retention charge included in the Company's analysis of whether customers receiving a fuel charge discount provide a contribution to fixed costs should be increased from 5.0 percent to 7.9 percent; (iii) PGC customers should be credited with the benefits which would have accrued under the storage management arrangement with VPEM unless Equitable can demonstrate that its decision to terminate this arrangement was consistent with least cost procurement; (iv) Equitable's time-differentiated exchanges have had an adverse impact on PGC customers and PGC rates should be adjusted; and (v) Equitable's proposal to include carrying charges on deferred storage withdrawals should be rejected. Next, I will address Mr. Gruber's concerns regarding the Company's hedging proposal. Finally, I will address Mr. Merrill's claims that the Commission has not enforced rigorous policies with respect to BTU content and retainage factors.

DESIGN PEAK DAY

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S DESIGN DAY ANALYSIS AND THE ASSOCIATED FIRM STANDBY AND BALANCING REQUIREMENTS.

A. The results of the study presented in the direct testimony of Equitable Witness Jeffrey Nehr, which was performed by Mr. Nehr under my supervision and direction, indicate the projected design day firm requirements are 480,883 dth and the projected firm requirements on Equitrans should be approximately 465,883 dth, net of Appalachian direct-feed supplies. The projected firm requirements on Equitrans include projected firm standby requirements equal to 24,168 dth and projected balancing requirements equal to 13,285 dth.

Q. WHY IS IT IMPORTANT TO IDENTIFY THE FIRM STANDBY REQUIREMENTS AND THE BALANCING REQUIREMENTS?

A. The Company contracts for sufficient capacity to meet the firm standby requirements and balancing requirements for its transportation customers. This capacity is not required for PGC purposes and is paid for by the transportation customers that elect these services. The Company provides an annual credit back to the PGC that compensates them, dollar for dollar, for the 24,168 dth of capacity used to provide firm standby service as well as the 13,285 dth of capacity that is used to provide the balancing service.

Q. DO YOU AGREE WITH MR. MIERZWA'S ANALYSIS INDICATING THE COMPANY CURRENTLY SECURES APPROXIMATELY 30,000 DTH OF CAPACITY IN EXCESS OF ITS CUSTOMERS' DESIGN PEAK DAY REQUIREMENTS?

A. No. Mr. Mierzwa has made several errors and bad assumptions in his design day analysis, identified in Schedule JDM-3 and Schedule JDM-4 attached to his direct testimony.

Q. PLEASE DESCRIBE THESE ERRORS AND BAD ASSUMPTIONS IN MORE DETAIL.

A. First of all, Mr. Mierzwa defines a design peak day as "... an extremely cold day that is expected to occur once every 10 to 20 years which a natural gas distribution company selects and utilizes for capacity planning purposes..." (Page 5, lines 22-24 of the Direct Testimony of Jerome D. Mierzwa). He then ignores the importance of using realistic weather data to simulate a design peak day by including only the January 2006 and February 2006 weather data in his regression analysis.

Q. WHY IS THE JANUARY 2006 AND FEBRUARY 2006 WEATHER DATA NOT RELIABLE FOR A DESIGN DAY ANALYSIS AND CAPACITY PLANNING?

A. January 2006 was one of the warmest January's on record. Mr. Mierzwa incorrectly assumes the lower customer usage experienced during January 2006 was attributable entirely to a high gas price environment. It was not. The customer usage declined because the weather was a non-factor. Had the weather during January 2006 been colder than normal, or even normal, the customer usage would have increased significantly and Mr. Mierzwa's results would have been dramatically different. Mr. Mierzwa is suggesting that the Company use weather data that was not indicative of design day conditions to forecast what future demand may be during design day conditions.

Q. WHAT ARE YOUR CONCERNS WITH USING WEATHER DATA THAT IS NOT REPRESENTATIVE OF DESIGN DAY CONDITIONS OR A PEAK DEMAND PERIOD?

A. Equitable purchases its gas supplies based on an acquisition strategy that minimizes gas purchase costs while assuring there is adequate, reliable supply. Assurance of "adequate and reliable" supply requires that planning be based on the need to maintain deliverability during peak demand periods under design day conditions. The weather experienced during January 2006 and February 2006 was not indicative of design day conditions. Therefore, that data should not be solely relied upon to make capacity planning decisions or project future demand requirements. Using only the weather data from January 2006 and February 2006 could result in the Company significantly understating its future capacity needs and could jeopardize service to essential human needs customers.

Q. SHOULD THE WEATHER DATA FROM JANUARY 2006 AND FEBRUARY 2006 BE COMPLETELY IGNORED?

A. No. This data should be used in conjunction with data from other relevant periods to project the Company's future demand requirements and capacity needs.

Q. WHY DID THE COMPANY NOT USE THIS DATA IN ITS ORIGINAL DESIGN DAY ANALYSIS?

A. At the time the Company was performing its original design day analysis, during the earlier part of January 2006, this information was not available. However, the Company did use the most recent information available.

Q. HAS THE COMPANY UPDATED ITS DESIGN DAY ANALYSIS TO INCLUDE THE JANUARY 2006 AND FEBRUARY 2006 DATA?

A. Yes. Equitable witness Jeffrey Nehr describes the Company's updated design day analysis in his rebuttal testimony.

Q. BASED UPON THE UPDATED DESIGN DAY STUDY, ARE THE COMPANY'S CURRENT CAPACITY LEVELS REPRESENTATIVE OF FUTURE PEAK DEMAND REQUIREMENTS?

A. Yes. The updated design day study, which includes the January 2006 and February 2006 data, indicates that the projected firm requirements, including 24,168 dth for firm standby and 13,285 dth for balancing, are approximately 473,119 dth. If the 15,000 dth per day of Appalachian direct-feed supplies are considered, the contractual capacity required is reduced to 458,119 dth. As previously mentioned, the contractual capacity on Equitrans is 458,091 dth per day. Therefore, the result is a negligible difference of 28 dth per day (458,119 – 458,019).

Q. DO YOU HAVE OTHER CONCERNS REGARDING MR. MIERZWA'S ANALYSIS?

A. Yes. As I mentioned earlier, Equitable's projected design day firm requirements are 480,883 dth. Equitable's total contractual capacity on Equitrans is 458,091 dth. Therefore, the capacity shortfall is 22,792 dth, not 8,000 dth as Mr. Mierzwa indicates at page 7, line 3, of his direct testimony.

Q. CAN YOU EXPLAIN THE DIFFERENCE?

A. It appears Mr. Mierzwa has reduced the 22,792 dth capacity shortfall by 15,000 dth, which is related to Appalachian direct-feed supplies.

Q. IS THIS CORRECT?

A. No. At page 6, lines 19-25 of his direct testimony, Mr. Mierzwa states that Equitable has secured a total of 473,091 dth per day of capacity. He includes the 458,091 dth of Equitrans capacity with 15,000 dth of Appalachian supply to arrive at 473,091 dth per day of total capacity. This is not correct. Mr. Mierzwa implies that the Company has secured 15,000 dth of Appalachian capacity. It has not. The contractual capacity on Equitrans available to meet projected demand requirements is 458,091 dth per day, not 473,091 dth per day.

In other words, the Company's projected design day firm requirements are 480,883, which includes standby requirements and balancing requirements equal to 24,168 dth and 13,285 dth, respectively. Instead of contracting for 480,883 dth per day of capacity on Equitrans, the Company is anticipating that approximately 15,000 dth per day of direct-feed supplies will be available during most winter seasons and can be used to meet the needs of its customers. As a result, the Company reduced the contractual capacity on Equitrans from 480,883 dth per day to 458,091 dth per day.

Q. IS THIS CONSISTENT WITH LEAST COST PROCUREMENT OBLIGATIONS?

A. Yes, it is. The Company is attempting to meet the firm requirements of its customers at the least possible cost, without jeopardizing reliability. Keep in mind a design day is expected to occur only once every 10 to 20 years.

Q. WILL THE COMPANY HAVE SUFFICIENT CAPACITY IF DESIGN DAY CONDITIONS OCCUR?

A. Yes. The PGC requirements are projected to be 443,430 dth [480,883 – 24,168 (standby) – 13,285 (balancing)]. The Company's contractual capacity on Equitrans is 458,091 dth per day. The 14,661 dth difference (458,091 - 443,430) is used to provide firm standby and/or balancing requirements to transportation customers.

Q. HAS EQUITABLE RECOGNIZED THAT HIGH PRICES COULD IMPACT ITS CUSTOMERS' REQUIREMENTS AS MR. MIERZWA SUGGESTS?

A. Yes, it has. The Company's prior contractual capacity level on Equitrans was 513,619 dth per day. Effective April 1, 2006, the new contractual capacity level on Equitrans is 458,091 dth per day. Compared to last year, the Company has reduced its contractual capacity on Equitrans by 55,528 dth per day.

Q. DOES EQUITABLE EXPECT TO EXAMINE WHETHER ITS PROPOSED ACQUISITION OF DOMINION PEOPLES WILL PROVIDE OPPORTUNITIES TO SHED CAPACITY IN THE FUTURE?

A. Yes. The Company continuously looks for ways to shed or replace capacity consistent with least cost procurement obligations. In fact, the Company has incentives under PBR Design No. 1 to perform capacity release transactions. These incentives are discussed in detail in my direct testimony.

Q. ARE THERE OTHER METHODS TO REDUCE CAPACITY COSTS IN LIEU OF STANDARD CAPACITY RELEASE TRANSACTIONS AS SUGGESTED BY MR. MIERZWA?

A. Possibly. Mr. Mierzwa suggests at page 11, lines 8-11, of his direct testimony that "...Equitable should aggressively pursue the realignment of its interstate pipeline capacity portfolio...to include attempting to renegotiate its current contracts, releasing excess capacity and examining whether its proposed merger with Dominion Peoples will provide opportunities to shed capacity..." In lieu of the standard capacity release transactions the Company could attempt to negotiate rates that are discounted from the pipeline's maximum tariff rates.

Q. HAS THE COMPANY ATTEMPTED TO RENEGOTIATE ANY OF ITS CAPACITY CONTRACTS?

A. Yes. The Company has aggressively pursued opportunities to renegotiate some of its capacity contracts. Specifically, Equitable has attempted to renegotiate and restructure its contract with Texas Eastern. To date, these attempts have been unsuccessful.

Q. HOW DOES THE COMPANY BELIEVE DISCOUNTED RATES ASSOCIATED WITH THESE CAPACITY CONTRACTS SHOULD BE TREATED?

A. As described above, the negotiated rate discount could be in lieu of a standard capacity release transaction. The net effect is that PGC customers would ultimately pay less whether it is through a capacity release mechanism credited to maximum rates or a negotiated discount from maximum rates. Therefore, the Company believes that these types of transactions, if they would materialize, should also be considered part of PBR Design No. 1.

FUEL RETENTION DISCOUNTS

Q. HAVE YOU REVIEWED OCA WITNESS MIERZWA'S TESTIMONY REGARDING FUEL RETENTION DISCOUNTS?

A. Yes, I have.

Q. PLEASE SUMMARIZE HIS POSITION.

A. Mr. Mierzwa recommends that the fuel retention charge included in the economic analysis of whether a customer provides a contribution to fixed costs should be increased to 7.9 percent. He also suggests that the costs associated with fuel retention discounts be recovered from all customers, not just the PGC sales customers. Finally, he believes that standards should be adopted with respect to the discounting of the retainage charges and base rates.

Q. IS IT APPROPRIATE TO USE A FUEL RETENTION CHARGE OF 7.9 PERCENT IN THE ECONOMIC ANALYSIS TO DETERMINE WHETHER A CUSTOMER PROVIDES A CONTRIBUTION TO FIXED COSTS, AS MR. MIERZWA HAS SUGGESTED?

A. No. Attached to my rebuttal testimony is an exhibit that is identified as Schedule SCR-1-R. This exhibit identifies the Company's lost and unaccounted for gas ("LUFG") for the past four years. The four-year average is 6.06 percent and the three-year average is 6.58 percent. I am not quite sure how Mr. Mierzwa developed the 7.9 percent LUFG figure that is referenced in his testimony since he did not provide supporting documents. Nevertheless, the Company's three-year average is 6.58 percent, not 7.9 percent as suggested by Mr. Mierzwa.

Q. SHOULD THE COMPANY USE 6.58 PERCENT INSTEAD OF 7.9 PERCENT IN THE ECONOMIC ANALYSIS TO DETERMINE WHETHER A CUSTOMER PROVIDES A CONTRIBUTION TO FIXED COSTS?

A. No, it should not.

Q. SHOULD THE COMPANY USE 6.58 PERCENT, WHICH IT REPRESENTS IS THE THREE-YEAR AVERAGE LUFG AMOUNT, INSTEAD OF 5.0 PERCENT IN THE ECONOMIC ANALYSIS TO DETERMINE WHETHER A CUSTOMER PROVIDES A CONTRIBUTION TO FIXED COSTS?

A. No. In my direct testimony, I explained in detail the impact that temperature and pressure compensated meters have on retainage calculations. The vast majority of the Company's large volume transportation customers have temperature and/or pressure compensated meters. As a result, my direct testimony recommended that those customers that have temperature and/or pressure compensated meters should not be held to the same contribution to LUFG as those customers without temperature and/or pressure compensated meters. The difference is roughly 2.5 percent, meaning that if a customer with a temperature and pressure compensated meter consumes 1,000 mcf, they should only be required to deliver 1,025 mcf to the Company.

Q. DID ANY OF THE PARTIES IN THIS PROCEEDING CHALLENGE THE COMPANY'S

TESTIMONY THAT CUSTOMERS HAVING TEMPERATURE AND PRESSURE *COMPENSATED METERS SHOULD NOT BE ASSESSED 5.0 PERCENT RETAINAGE?*

A. No.

Q. GOING FORWARD, WILL THE COMPANY ASSESS CUSTOMERS THAT HAVE TEMPERATURE AND PRESSURE COMPENSATED METERS ONLY 2.5 PERCENT RETAINAGE?

A. No, the Company is not proposing any changes. The Company will continue to assess all transportation customers 5.0 percent retainage. However, the economic analysis to determine whether a customer provides a contribution to fixed costs should use 2.5 percent if that transportation customer has temperature and/or pressure compensated meter(s). If the *transportation customer does* __not__ possess *temperature and/or pressure compensated meter(s),* the economic analysis to determine whether a customer provides a contribution to fixed costs should use 5.0 percent.

Q. SHOULD THE COMPANY ASSESS TRANSPORTATION CUSTOMERS WITHOUT TEMPERATURE AND PRESSURE COMPENSATED METERS 6.58 PERCENT RETAINAGE INSTEAD OF 5.0 PERCENT?

A. The Company is currently assessing all transportation customers, with or without temperature and pressure compensated meters, 5.0 percent retainage. The only exceptions are the seven customers previously identified by Equitable witness John Quinn. The Company has nearly 7,000 large volume customers with temperature and/or pressure compensated meters. (Please refer to the attached response to interrogatories of the Office of Consumer Advocate, identified as OCA-II-14) Only seven customers have discounted retainage charges. The remaining customers are being assessed 5.0 percent retainage.

Q. ARE THESE REMAINING CUSTOMERS CONTRIBUTING TOWARDS THE COSTS

ASSOCIATED WITH THE FUEL RETENTION DISCOUNTS AFFORDED TO THE SEVEN CUSTOMERS RECEIVING DISCOUNTED RETAINAGE?

A. Yes, they are, although we maintain that the contribution received from the seven customers is fully compensatory. In fact, Mr. Mierzwa has also suggested that the costs associated with fuel retention discounts be recovered from all customers, not just the PGC sales customers. By charging transportation customers with temperature and/or pressure compensated meters 5.0 percent retainage instead of 2.5 percent retainage, the Company is ensuring that all customers, not just the PGC sales customers, contribute towards the costs associated with fuel retention discounts.

Q. MR. MIERZWA HAS SUGGESTED RAISING THE GENERALLY APPLICABLE RETAINAGE CHARGE TO 10 PERCENT FROM 5.0 PERCENT. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Mr. Mierzwa makes this recommendation because he believes PGC customers would effectively pay a retainage charge of nearly 13 percent if transportation customers continue to be assessed 5.0 percent retainage.

Q. ARE PGC CUSTOMERS BEING CHARGED NEARLY 13 PERCENT RETAINAGE?

A. No. As I explained earlier, the Company's three-year average LUFG is only 6.58 percent. Furthermore, nearly all of the transportation customers with temperature and/or pressure compensated meters are paying 5.0 percent retainage instead of 2.5 percent. This ultimately reduces the amount of retainage paid by PGC customers.

Q. ARE PGC CUSTOMERS PAYING HIGHER RETAINAGE RATES THAN TRANSPORTATION CUSTOMERS WITHOUT TEMPERATURE AND PRESSURE COMPENSATED METERS?

A. Yes. Transportation customers that do not have temperature and/or pressure compensated meters are effectively paying 5.0 percent retainage. PGC customers are paying a retainage rate that is somewhat higher.

Q. IS IT APPROPRIATE FOR PGC CUSTOMERS TO PAY A HIGHER RETAINAGE RATE THAN TRANSPORTATION CUSTOMERS?

A. In certain instances, it is appropriate for PGC customers to pay a higher retainage rate.

Q. WHEN WOULD IT BE APPROPRIATE?

A. The Company has invested significant capital during the past several years as part of the Northern Asset Optimization Program ("NAOP"). The NAOP is designed to attract and increase the amounts of local Appalachian production on the system. This increased Appalachian production affords Equitable opportunities to reduce its reliance on interstate pipeline supplies and save on the variable costs associated with transporting this gas from the Texas and Louisiana production areas to Western Pennsylvania. These avoided transportation costs are certainly a benefit to our customers. As I explained earlier, compared to last year, the Company has reduced its contractual capacity on Equitrans by 55,528 dth per day. The tradeoff, however, is that there will be slightly higher retainage rates on the Company's distribution/gathering systems due to increased Company usage for compression, among other things.

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION REGARDING WHICH RETENTION CHARGE SHOULD BE INCLUDED IN THE ECONOMIC ANALYSIS TO DETERMINE WHETHER A CUSTOMER PROVIDES A CONTRIBUTION TO FIXED COSTS?

A. The Company's direct testimony proposed that the appropriate retention charge for any economic analysis for customers that have temperature and/or pressure compensated meters should be 2.5 percent, not 7.9 percent as suggested by Mr. Mierzwa. We still believe that to be the case.

Q. WHAT IS THE APPROPRIATE RETAINAGE CHARGE TO BE ASSESSED CUSTOMERS IN GENERAL?

A. The appropriate retainage charge should be 5.0 percent. PGC customers will continue to be assessed the actual retainage amount, which was approximately 6.58 percent during the period 2002 -2005. Absent recovering the 5.0 percent retainage contributions from transportation customers that have temperature and/or pressure compensated meters, the actual retainage amount assessed to PGC customers would have been significantly higher than 6.58 percent.

STORAGE MANAGEMENT ARRANGEMENT

Q. PLEASE DESCRIBE OCA WITNESS MIERZWA'S POSITION WITH RESPECT TO THE COMPANY'S STORAGE MANAGEMENT ARRANGEMENT WITH VIRGINIA POWER ENERGY MARKETING.

A. Mr. Mierzwa believes that the Company should not have rescinded the storage management arrangement with Virginia Power Energy Marketing ("VPEM") unless the Company can demonstrate that the decision to rescind the arrangement was consistent with least cost gas procurement. If Equitable cannot provide this demonstration he recommends that all of the $2.6 million fee that would have accrued under the VPEM arrangement be credited to PGC customers.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Absolutely not. Mr. Mierzwa did not provide any analysis that demonstrates how the Company's decision to rescind the storage management arrangement adversely impacted

PGC customers. Mr. Mierzwa admits on page 23, lines 5-8, of his direct testimony that the OCA argued that this arrangement created additional risk of higher gas costs for PGC customers. The Company does not believe an analysis is required to justify its decision to rescind the storage management arrangement. In its Order on Reconsideration in last year's 1307(f) proceeding, the Commission finally and completely resolved matters related to the VPEM arrangement stating that "Equitable acted within its managerial authority by rescinding the "VPEM Arrangement" and [a]ccordingly, there is no issue remaining for review within the parameters of Equitable's 2006 1307(f) proceeding."

Q. WHAT DID THE COMPANY DO WITH THE STORAGE AND/OR TRANSPORTATION CAPACITY THAT WAS HISTORICALLY RELEASED TO VPEM AS PART OF THE STORAGE MANAGEMENT ARRANGEMENT?

A. I explained in my direct testimony that the Company was able to monetize some of the value associated with these contracts. Specifically, the Company released the transportation capacity, subject to recall, at maximum rates. However, the Company did not release the storage capacity because of the arguments made by the OCA during last year's proceeding that this arrangement restricted storage flexibility. The Company's decision to terminate the arrangement was found by the Commission to be clearly within its managerial discretion. Likewise, the Company's decision to release the transportation capacity and provide total capacity release revenue equal to nearly $750,000 was also within Equitable's managerial discretion. The Company could not have provided the capacity release credits if it had not rescinded the storage management arrangement. Certainly, the Company's decision to rescind the storage management arrangement but still provide capacity release credits to PGC customers in excess of $560,000 (75% x $750,000) by eliminating the OCA's restricted storage flexibility argument while still monetizing the transportation value associated with these contracts, should not be construed as a violation of least cost gas procurement. In effect, the OCA is advocating analysis by hindsight, which is inconsistent with least cost purchasing principles.

TIME DIFFERENTIATED EXCHANGES

Q. *PLEASE DESCRIBE OCA WITNESS MIERZWA'S POSITION WITH RESPECT TO THE COMPANY'S TIME DIFFERENTIATED EXCHANGE TRANSACTIONS.*

A. Mr. Mierzwa believes that the Company's three exchange transactions had an adverse impact on PGC customers. He believes that these transactions required the Company to purchase gas in a higher priced environment in order to effectuate the transactions.

Q. DID THESE EXCHANGE TRANSACTIONS IN FACT REQUIRE THE COMPANY TO PURCHASE GAS IN A HIGHER PRICED ENVIRONMENT?

A. No. I am not certain Mr. Mierzwa fully understands the manner in which these transactions were effectuated.

Q. WOULD YOU PLEASE DESCRIBE THESE EXCHANGE TRANSACTIONS IN MORE DETAIL?

A. The three exchanges were considered "park" transactions. Various third-parties gave gas to Equitable in one month and Equitable returned the gas during a later month. The Company did not purchase this gas, nor did it incur any cost related to this gas. The Company conducted its gas supply planning and purchase activity during those months as if the park transactions never occurred. Mr. Mierzwa believes these park transactions adversely impacted PGC customers by $3,548,200.

Q. DID THE PARK TRANSACTIONS ADVERSELY IMPACT PGC CUSTOMERS?

A. No. Mr. Mierzwa believes that when the gas is returned to the third-party the

Company must either withdraw additional gas from storage or purchase additional gas supplies. This is not correct. He then attempts to place a value on the gas in each of the months using the applicable NYMEX settlement price. Again, this type of analysis is simply inaccurate. First of all, the NYMEX settlement price has nothing to do with the park transaction other than to assess the appropriate fee to charge or to collect. Secondly, the third-parties purchased the gas, not the Company. When it came time to return the gas, the Company did so. The Company was simply holding the gas for the third-party for redelivery later. Of course, the Company was paid a fee to hold the gas during that particular time period. The Company did not withdraw additional gas from storage or purchase additional gas supplies. It simply returned the gas that was received several months prior.

Q. DID THE COMPANY INJECT THIS GAS INTO STORAGE OR USE IT TO MEET CURRENT CUSTOMER REQUIREMENTS AS MR. MIERZWA CLAIMS?

A. No. The gas was parked on the system and held for the duration of the particular park transaction. I have attached to my rebuttal testimony an exhibit identified as Schedule SCR-2-R that summarizes the park transactions. Schedule SCR-2-R also identifies the corresponding monthly no-notice imbalance positions.

Q. WHAT IS THE SIGNIFICANCE OF THE MONTHLY NO-NOTICE IMBALANCE POSITIONS IDENTIFIED IN SCHEDULE SCR-2-R?

A. I have identified in Schedule SCR-2-R the respective month-beginning imbalance and month-ending imbalance positions for the Company's no-notice service on Equitrans. For example, during April 2005, the month-beginning imbalance position was a negative 218,742 dth. In other words, Equitable owed 218,742 dth to Equitrans. The month-ending imbalance position was a positive 45,487 dth, i.e., Equitrans owed 45,487 dth to Equitable Gas Company. The difference between the month-beginning imbalance and the month-ending imbalance was 264,229 dth. In summary, Equitable paid back to Equitrans the 218,742 dth that was owed at the beginning of the month and built a positive imbalance of 45,487 dth. This was accomplished primarily as a result of the park transaction for 200,000 dth. The significance of these monthly no-notice imbalance positions is to verify that the park gas was not injected into storage or used to meet customer requirements as Mr. Mierzwa has suggested. The park gas was banked on the interstate pipeline in the Company's no-notice service.

Q. DID THE COMPANY OR PGC CUSTOMERS INCUR ANY ADDITIONAL FEES FROM EQUITRANS FOR THESE PARK TRANSACTIONS?

A. No. The Company did not incur any additional fees as a result of these transactions.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH MR. MIERZWA'S RECOMMENDED ADJUSTMENT?

A. First of all, Mr. Mierzwa's recommended adjustment is flawed because he assumes that the Company purchases additional gas, at market prices, when the parked gas is returned. I have explained previously that this does not happen, but let's assume, for the sake of argument, that the Company had to replace these supplies. It can do so by purchasing additional supplies or withdrawing additional gas from storage. Mr. Mierzwa's analysis does not take into consideration the possibility of withdrawing additional gas from storage in lieu of purchasing additional supplies. Secondly, Mr. Mierzwa fails to consider the exchange fees that were credited to the PGC customers as part of PBR Design No. 1.

Q. HOW DOES MR. MIERZWA'S ANALYSIS CHANGE IF THE ASSUMPTION IS THAT THE COMPANY WITHDRAWS GAS FROM STORAGE INSTEAD OF PURCHASING ADDITIONAL SUPPLIES?

A. I have attached Equitable Schedule SCR-3-R that identifies the impact of withdrawing additional gas from storage instead of purchasing additional supplies, as suggested by Mr. Mierzwa. The impact of this scenario reduces Mr. Mierzwa's adjustment from $3,548,220 to $998,530.

Q. WOULD IT BE REASONABLE TO ASSUME THE COMPANY COULD MAKE ADDITIONAL STORAGE WITHDRAWALS INSTEAD OF PURCHASING ADDITIONAL SUPPLIES?

A. Yes, it would. As I explained earlier in my rebuttal testimony, the weather experienced this past winter was warmer than normal and created a storage surplus. The Company minimized its pipeline purchases all winter in an effort to withdraw as much storage as possible.

Q. WAS THE COMPANY ABLE TO WITHDRAW ALL OF ITS STORAGE?

A. No. The warm winter did not permit the Company to withdraw its storage inventory. In fact, the Company was only able to withdraw approximately 75% of its storage inventory.

Q. HOW DO THE EXCHANGE FEES IMPACT MR. MIERZWA'S ANALYSIS?

A. Mr. Mierzwa has failed to recognize the credit to the PGC as a result of these park transactions. The fees realized from these transactions totalled $470,000. Therefore, even if we were to accept his recommendation, his adjustment should be reduced from $3,548,200 to $3,078,200 ($3,548,200 - $470,000). Furthermore, the analysis presented in Schedule SCR-3-R indicates that the impact of using additional storage instead of purchasing additional supplies would further reduce any adjustment to $528,530 after reflecting the $470,000 in exchange fees. At most, the adjustment would be $528,530, not $3,548,200 as suggested by Mr. Mierzwa.

Q. WHAT DID THE COMMISSION, IN LAST YEAR'S PROCEEDING AT DOCKET NO. R-00050272, CONCLUDE REGARDING EQUITABLE'S EXCHANGE

TRANSACTIONS?

A. Basically, the Commission adopted the ALJ's recommendation and the OCA's position that Equitable had failed to adequately explain just how the parked gas is handled (Page 23 of the Commission's Opinion and Order, dated September 28, 2005). Schedule SCR-2-R explains in detail exactly how the parked gas is handled. It is parked as an imbalance in the Company's no-notice service.

Q. WILL THE COMPANY CONTINUE TO PERFORM THESE TRANSACTIONS IF IT CONTINUES TO BE SECOND-GUESSED BY THE OCA?

A. The Company believes there are opportunities to provide significant benefits to the PGC customers by efficiently utilizing the capacity portfolio and capitalizing on market movements. Since October 2003, the Company has provided credits to PGC customers (related to PBR Design No. 1) of nearly $5 million. However, the continual second-guessing by the OCA related to these transactions, e.g., exchange transactions, storage management arrangements, off-system sales, is causing the Company to seriously reevaluate the risk / reward associated with maximizing the portfolio's value, especially when the OCA's position is another hindsight analysis.

CARRYING CHARGES ON DEFERRED STORAGE WITHDRAWALS

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL REGARDING CARRYING CHARGES ON DEFERRED STORAGE WITHDRAWALS?

A. The Company is proposing to recover in PGC rates the carrying charges associated with deferred storage withdrawals or "rolling the storage inventory to a future period". The Company is only proposing to recover these costs if it can demonstrate that this action provided benefits to PGC customers.

Q. WHAT ARE OCA WITNESS MIERZWA'S CONCERNS REGARDING THE COMPANY'S PROPOSAL?

A. Mr. Mierzwa believes the Company's current base rates include an allowance for the recovery of storage inventory carrying charges. He believes the Company is selectively adjusting one element of base rates while ignoring other items which may have increased base rate margins which he maintains constitutes single issue ratemaking. Finally, he is concerned that the Company's proposal does not explain how these carrying charges will be determined.

Q. DO YOU BELIEVE THE COMPANY'S CURRENT BASE RATES INCLUDE AN ALLOWANCE FOR ALL STORAGE INVENTORY CARRYING CHARGES?

A. No, I do not, especially when one remembers that Equitable's last base rate case was almost ten years ago. The Company has changed its capacity portfolio dramatically since its last base rate case by significantly increasing its contractual storage capacity. I discussed in my direct testimony the Company's capacity entitlements on Equitrans, effective April 1, 2006. The Company's storage capacity has increased from 8,969,464 dth to 12,756,653 dth, an increase of 3,787,189 dth. Furthermore, the Company's acquisition of Dominion storage, also discussed in detail in my direct testimony, occurred after the Company's last base rate case. The total Dominion storage is an additional 3,100,000 dth. In summary, the Company's recent acquisition of nearly 7,000,000 dth of new storage has more than doubled the storage capacity which was in place during the last base rate case. There is no way the Company's current base rates include an allowance for these additional storage inventory carrying charges.

Q. DOES THE COMPANY'S PROPOSAL CONSTITUTE SINGLE ISSUE RATEMAKING BY SELECTIVELY ADJUSTING ONE ELEMENT OF BASE RATES WHILE

IGNORING OTHER ITEMS WHICH MAY HAVE INCREASED BASE RATE MARGINS?

A. No. As I explained earlier, there is no element in the Company's base rates that compensates the Company for the additional carrying charges associated with the recently acquired storage capacity. If the Company's storage capacity had actually decreased since the last base rate case and the Company made this proposal, I could understand Mr. Mierzwa's position. However, that is simply not the case.

Q. *PLEASE PROVIDE A NUMERICAL EXAMPLE INDICATING HOW THE COMPANY'S* PROPOSAL WOULD BE STRUCTURED, INCLUDING HOW THE CARRYING CHARGES WILL BE DETERMINED.

A. The Company is proposing to recover the carrying charges associated with rolling the storage inventory as a purchased gas cost expense. These expenses would be identified on a monthly basis and included as gas costs in the Company's quarterly gas cost filings. The carrying charges on these under-recovered purchased gas costs will be recovered quarterly and the short-term cost of debt will be based on the monthly Morgan Stanley quote to Equitable Resources, Inc., for commercial paper. I have included an exhibit identified as Schedule SCR-4-R that provides a numerical example detailing the structure of the Company's proposal.

HEDGING PROPOSAL

Q. WHAT CONCERNS DOES OTS WITNESS GRUBER HAVE REGARDING THE COMPANY'S GAS SUPPLY HEDGING PROGRAM ("PROGRAM")?

A. Mr. Gruber is concerned that the Company is seeking pre-approval that its proposed Program satisfies least cost procurement obligations. He is also concerned that the Company is asking the OTS to waive its rights to examine the results of the Program and the underlying reasons behind the decisions made to hedge gas costs.

Q. ARE YOU ASKING FOR SUCH APPROVALS?

A. No. Equitable is <u>not</u> seeking pre-approval that its proposed Program satisfies least cost procurement obligations, nor is it asking the OTS to waive its rights to examine the results of the Program and the underlying reasons behind the decisions made to hedge gas costs.

Q. WHAT EXACTLY IS THE COMPANY ASKING FROM THE OTS?

A. The Company is asking the OTS, as well as the OCA and the OSBA, to recognize that the Program is appropriate and the "hedging concept" is consistent with least cost purchasing obligations. The OTS, and any other party for that matter, has the right to examine the results of the Program and the reasons behind our hedging activity. In fact, the Program specifically states "...Any gas cost increases and/or reductions that occur as a result of Equitable implementing this Program will be recovered in the quarterly gas cost filings and *are subject to review during the annual 1307(f) proceedings* (emphasis added)..." The Company is asking all of the parties to support our entering into the Program as well as the administration of the Program. If the Company adheres to the administration and management of the Program, as described, then the gas purchase decisions that occur are considered to be consistent with least cost purchasing obligations.

Q. HAVE THE OCA AND OSBA PROVIDED RECOMMENDATIONS REGARDING THE COMPANY'S HEDGING PROPOSAL?

A. Yes. The OCA and OSBA have recommended that the Company proceed with the hedging program.

BTU CONTENT AND RETAINAGE FACTORS

Q. DO YOU AGREE WITH NRG WITNESS MERRILL'S COMMENTS THAT THE COMMISSION HAS NOT ENFORCED A RIGOROUS POLICY WITH RESPECT TO

EQUITABLE'S TESTING AND VERIFYING BTU CONTENT AND THAT EQUITABLE SHOULD HAVE TO VERIFY AND MANAGE ITS RETAINAGE FACTOR?

A. No. In fact, I believe it is just the opposite. The Commission requires the Company to provide detailed information during the annual 1307(f) proceedings identifying the Btu content associated with its various gas supply resources. The Company's numerous gas chromatographs are checked on a regular basis and calibrated according to industry specifications. In addition, the Company provides detailed information regarding its lost and unaccounted for, or retainage, statistics. I have attached to my rebuttal testimony an interrogatory response identified as OCA-II-25 that identifies for calendar year 2005, the applicable Btu content and retainage factors. Based upon this data, the Company is proposing to keep the system average Btu content equal to 1.06 for assessing future transportation supply requirements.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does. However, there are several interrogatory responses outstanding from other parties that I have not received. Therefore,.I reserve the right to file supplemental rebuttal testimony once these responses are received.

SCHEDULE SCR-1-R

YEAR	Total Supply		Accrued Thruput		Company Use		Unaccounted for Gas	
	Mcf	MMbtu (dth)	Mcf	MMBtu	Mcf	MMbtu(dth)	Mcf	UFG %
2002	57.927.759	60.918.686	55,006.625	57.849.995	296.927	312,248	2,624,207	4 50%
2003	58.121.112	61,546.947	54.739.143	57.921.294	272.382	288.425	3.109.588	5 40%
2004	59.193.339	62,240.651	54.863.684	57.684.742	283.264	297.852	4.046.391	6 80%
2005	53.818.017	56.400.274	49.045.723	51.598.809	472.545	498.611	4.572.294	8 50%
2002 - 2005 4-year average	228.860.227	241,106,539	213,655,174	225,054,840	1.325,118	1,397.137	13.879,935	6 06%
2003 - 2005 3-year average	170,932.469	180,187.873	158.648.549	167.204.845	1.028.192	1.084.889	11.255.728	6 58%

SCHEDULE SCR-2-R

Summary of 2005 Park Transactions

Delivered to Equitable	Location	Monthly Volumes	Revenues	No-Notice Imbalance (Dth)		Returned by Equitable	No-Notice Imbalance (Dth)	
April 2005	Texas Eastern /	200,000	$150,000			December 2005		
	Equitrans			(218,742)	month-beginning balance		417,161	month-beginning balance
	into No-Notice			45,487	month-ending balance		(343,778)	month-ending balance
May 2005	Texas Eastern /	300,000	$165,000			November 2005		
	Equitrans			45,487	month-beginning balance		83,134	month-beginning balance
	into No-Notice			449,896	month-ending balance		417,161	month-ending balance
July 2005	Texas Eastern /	155,000	$155,000			December 2005		
	Equitrans			536,828	month-beginning balance		417,161	month-beginning balance
	into No-Notice			673,038	month-ending balance		(343,778)	month-ending balance

SCHEDULE SCR-3-R

	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	
					(3 - 2)	(4 x 1)		(6 - 2)	(7 x 1)	
Delivered to Equitable	Monthly Volumes	NYMEX Settle	Returned by Equitable	NYMEX Settle	NYMEX Difference	Mierzwa Recommended Adjustment	Storage Wacog	Difference /1	Revised Adjustment	
April 2005	200.000	$7 323	December 2005	$11 180	$3 857	$771.400	$8 502	$1.179	$235.800	
May 2005	300.000	$6 748	November 2005	$13 832	$7 084	$2,125.200	$8 502	$1 754	$526.200	
July 2005	155.000	$6 976	December 2005	$11 180	$4 204	$651,620	$8 502	$1 526	$236,530	
						$3.548.220			$998.530	
									($470,000)	exchange fees
									$528,530	

/1 assumes additional storage withdrawals instead of purchasing additional supplies

SCHEDULE SCR-4-R

Calculation of Interest on Deferred Storage Withdrawals

	Deferred Amount /1	Interest Rate /2	Annual Interest	Month Interest
April	$ 21,000,000	2.13%	$ 447,300	$ 37,275
May		2.33%	$ 489,300	$ 40,775
June		2.41%	$ 506,100	$ 42,175
July		2.55%	$ 535,500	$ 44,625
August		2.76%	$ 579,600	$ 48,300
September		3.00%	$ 630,000	$ 52,500
October		3.07%	$ 644,700	$ 53,725
November	$ 21,000,000	3.32%	$ 697,200	$ 58,100
December	$ 16,800,000	3.32%	$ 557,760	$ 46,480
January	$ 12,600,000	3.07%	$ 386,820	$ 32,235
February	$ 8,400,000	3.00%	$ 252,000	$ 21,000
March	$ 4,200,000	2.76%	$ 115,920	$ 9,660
Total Interest				$ 486,850

1/ deferred amount assumes 3.5 Bcf at wacog equal to $6.00/dth starting April;
2.8 Bcf November 30; 2.1 Bcf December 31; 1.7 Bcf January 31; 0.7 Bcf February 28 and 0 Bcf March 31

2/ Interest Rates reflect the Company's monthly average Short Term variable Borrowing rate

Docket No. R-00061295
Item: OCA-II-14
Respondent: Stephen C. Rafferty
Position: Vice-President, Utility Asset Management

EQUITABLE GAS COMPANY
Response to Interrogatories of the
Office of Consumer Advocate

Item: OCA-II-14

By customer class, identify the extent to which customer meters are pressure and temperature correcting. Also identify Equitable's plans to install additional pressure and temperature correcting meters.

Response:

Please see the attached.

Active meters in the field that are Temperature and/or Pressure Compensated
as of 5/5/2006

	Temperature Compensated	Temerature and Pressure Compensated	TOTAL
Residential	2,510	0	**2,510**
Commercial	6,032	668	**6,700**
TOTAL	**8,542**	**668**	**9,210**

Average number of residential meters changes per year (last 2 years) = 3,700
As residential meters are replaced they are being replaced with temperature compensating meters

ORIGINAL

Docket No. R-00061295

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

EQUITABLE GAS COMPANY

Division of

EQUITABLE RESOURCES, INC.

Before the

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Computation of Annual Purchased Gas Cost

For the Twelve Months Ending September 2007

EXHIBIT I

DOCUMENT FOLDER

INFORMATION SUBMITTED PURSUANT TO:

Title 52 Pennsylvania Code § 53.61 et seq.,
Pa PUC Regulations Re Filing of Rate Changes

DOCKETED
SEP 2 2 2006

Filed April 1, 2006

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(a) A Section 1307(f) gas utility may only voluntarily file a tariff reflecting an increase or decrease in natural gas costs once a year in accordance with the schedule established by the Commission, as published in the Pennsylvania Bulletin prior to the first day of September of each preceding year . . .

Response: See Table of Contents below designating the calculation of the Purchased Gas Cost as well as the proposed tariff pages.

Table of Contents

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(a) A Section 1307(f) gas utility may only voluntarily file a tariff reflecting an increase or decrease in natural gas costs once a year in accordance with the schedule established by the Commission, as published in the Pennsylvania Bulletin prior to the first day of September of each preceding year . . .

Response: See Table of Contents below designating the calculation of the Purchased Gas Cost as well as the proposed tariff pages.

Table of Contents (continued)

Equitable Gas Company
Pennsylvania Division

Computation of Purchased Gas Costs for the
12 Months Ending September 2007

			Proposed Purchased Gas Cost	
1	'C' - Cost of Gas for the 12 Months Ending September 30, 2007	Part B; Sheet 2 of 8	$255,598,994	
2	E' - Experienced Net Undercollection	Part A; Sheet 2 of 6	($18,023,397)	
3	'S' - Projected 1307(f) Sales	Part B; Sheet 1 of 8	24,249,100	Mcf
4	C Factor		10.54	/Mcf
5	E Factor	Part A; Sheet 2 of 6	0.74	/Mcf
6	Proposed Purchased Gas Cost per Mcf		11.28	/Mcf
7	Current Purchased Gas Cost per Mcf		14.26	/Mcf
8	Total Decrease in Purchased Gas Cost to be reflected in Tariff Rates		($2.98)	/Mcf

Pennsylvania Division

Determination of E Factor

Line No.	Description	Sheet Reference	Amount (1)	
1	Actual Over/(Under) Collection for the 12 Months Ending December 2005	Part D; Sheet 1 of 4	(23,398,241)	
2	Estimated Over/(Under) Collection for the 9 Months Ending September 2006	Part C; Sheet 1 of 7	9,194,653	
3	'E' Factor Over/(Under) Collections	Part A; Sheet 3 of 6	(2,748,457)	
4	Supplier Refunds	Part A; Sheet 4 of 6	0	
5	Eliminate Exchange Transcations	See Note Below	380,720	
6	Interest	Part A; Sheet 5 of 6	(1,452,072)	
7	Total Proposed E Factor		$ (18,023,397)	
8	Projected 1307(f) Sales Throughput		24,249,100	Mcf
9	E Factor Rate		0.74	/Mcf

Note: Consistent with the Commission's decision in Docket No. R-00050272, the Company has eliminated exchange transaction revenue recovered during 2004.

Pennsylvania Division

E Factor Over/(Under) Collection for the
18 Months Ending September 2007

Estimated Versus Actual Recovery -Jan. 1, 2005 - Sept. 30,2005			Dollars
Actual Volumes Sold - Mcf	16,514,503	0.27	4,458,916
Actual Volumes Sold - Mcf			
Actual Volumes Sold - Mcf			
Estimated Recoveries			4,503,031
Amount Due			(44,115)
Estimated Versus Actual Migration Recovery -Jan. 1, 2005 - Sept. 30, 2005			
Actual Migration			
Estimated Migration	-		
Amount Due Customer			0
Estimated Versus Actual (Reverse) Migration -Jan. 1, 2005 - Sept. 30, 2005			
Actual (Reverse) Migration			
Estimated (Reverse) Migration	-		
Amount Due Customer			0
Estimated and Actual Recovery - 12 Months Ending September 2005			
Amount Due Company Per Commission Order in Docket No. R-00050272 updated for the Company's 10/1/05 Quarterly Gas Cost Filing			(28,039,271)
Estimated/Actual Volumes Sold - Mcf			
October 1, 2005 - October 30, 2005	14,546	0.27	3,927
October 1, 2005 - December 2005	7,566,477	1.09	8,247,460
Estimated PGC Volumes Sold - Mcf			
January 2006 - September 2006	15,390,579	1.11	17,083,542
Estimated/Actual Transportation Migration Volumes Sold - Mcf			
October 1, 2005 - December 31,2005			
January 2006 - September 2006			
Estimated/Actual (Reverse) Migration Volumes Sold - Mcf			
October 1, 2005 - December 31,2005			
January 2006 - September 2006			
Amount Due Company			(2,704,342)
Total 'E' Factor Over/(Under) Collection to be Included in Purchased Gas Costs			(2,748,457)

Equitable Gas Company
Pennsylvania Division

Summary of Supplier Refunds Received

	Total Included in PGC 2006
	$
Total Refund Amount - $	$0

Equitable Gas Company
Pennsylvania Division

Calculation of Interest on Over/Under Collections

Line No.	Description	Actual Over/(Under) Collection	Time Period	Interest Rate	Actual Interest	Interest Included in PGC 05	Interest Included in Interim Rate
		(1)	(2)	(3)	(4)	(5)	(6)
		$	Years		$	$	$
					(1)x(2)x(3)		
1	January 2005	(4,521,447)	1.2500	6.00%	(339,109)	(339,109)	0
2	February	3,756,039	1.1667	6.00%	262,930	262,930	0
3	March	(2,459,208)	1.0834	6.00%	(159,858)	(159,858)	0
4	April	3,374,954	1.0000	6.00%	202,497	202,497	0
5	May	(1,992,000)	0.9167	6.00%	(109,564)	(109,564)	0
6	June	(7,220,806)	0.8334	6.00%	(361,069)	(361,069)	0
7	July	(5,998,956)	0.7500	6.00%	(269,953)	(269,953)	0
8	August	791,901	0.6667	6.00%	31,678	31,678	0
9	September	1,782,240	0.5834	6.00%	62,386	(29,072)	91,458
10	October	(411,265)	1.5000	6.00%	(37,014)	0	(37,014)
11	November	(18,700,425)	1.4167	6.00%	(1,589,574)	0	(1,589,574)
12	December	(6,899,330)	1.3334	6.00%	(551,974)	0	(551,974)
13	Total 2005	(38,498,304)			(2,858,624)	(771,520)	(2,087,104)
	Interim Period						
14	January 2006	(5,297,453)	1.2500	6.00%	(397,309)	-	(397,309)
15	February	3,971,711	1.1667	6.00%	278,028	-	278,028
16	March	6,400,946	1.0834	6.00%	416,087	-	416,087
17	April	8,591,907	1.0000	6.00%	515,514	-	515,514
18	May	1,108,070	0.9167	6.00%	60,946	-	60,946
19	June	(1,376,008)	0.8334	6.00%	(68,806)	-	(68,806)
20	July	(1,476,427)	0.7500	6.00%	(66,439)	-	(66,439)
21	August	(1,499,770)	0.6667	6.00%	(59,994)	-	(59,994)
22	September	(1,228,322)	0.5834	6.00%	(42,996)	-	(42,996)
23	Total Interim	9,194,653			635,031		635,031
24	Total to be Included in PGC 2006						(1,452,072)

Summary of Proposed Rates to become
Effective for Service Rendered on and after
October 1, 2006

	Current Total Rates	Current PGC Rate	Proposed PGC Rate	Proposed PGC Decrease	STAS	Proposed Total Rates
	(1)	(2)	(3)	(4)	(5)	(6)
	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf
				(3) - (2)		(1)+(4)+(5)
Equitable Gas Company						
Residential (Rate RS)						
All Usage	17.490	14.26	11.28	(2.98)	0.000	14.510
General Service Small (Rate GSS)						
All Usage	17.167	14.26	11.28	(2.98)	0.000	14.187
General Service Large (Rate GSL)						
All Usage	16.970	14.26	11.28	(2.98)	0.000	13.990

(a) Excludes meter charges.

Pennsylvania Division

Summary of Estimated PGC Sales and Supply Requirements
for the Period October 2006 through September 2007

Line No.	Description	2006 October	November	December	2007 January	February	March	April	May	June	July	August	September	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	PGC Sales - Mcf													
1	Residential	1,079,353	2,108,612	3,222,205	3,887,113	3,382,608	2,736,776	1,639,446	669,742	354,297	363,505	362,726	402,456	20,208,839
2	Small Commercial	135,971	226,576	342,371	424,988	368,697	313,552	190,321	96,037	63,274	60,993	65,152	68,803	2,356,735
3	Small Industrial	628	1,080	1,606	1,979	1,739	1,428	903	443	305	270	265	307	10,953
4	Large Commercial	93,228	154,657	231,051	287,905	250,545	215,531	131,397	69,089	47,742	45,504	47,784	50,895	1,625,328
5	Large Industrial	2,825	4,365	6,607	7,854	6,897	6,000	3,899	2,163	1,760	1,628	1,683	1,564	47,245
6	Total PGC Sales	1,312,005	2,495,290	3,803,840	4,609,839	4,010,486	3,273,287	1,965,966	837,474	467,378	471,900	477,610	524,025	24,249,100
	Company Use	4,396	8,361	12,746	15,446	13,438	10,968	6,587	2,806	1,566	1,581	1,600	1,756	81,251
7	UFG	69,284	131,771	200,873	243,436	211,785	172,856	103,819	44,225	24,681	24,920	25,222	27,673	1,280,545
8	Total Demand - Mcf	1,385,685	2,635,422	4,017,459	4,868,721	4,235,709	3,457,111	2,076,372	884,505	493,625	498,401	504,432	553,454	25,610,896
9	BTU Conversion	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	-
10	Total Demand - Dth	1,468,826	2,793,547	4,258,507	5,160,844	4,489,852	3,664,538	2,200,954	937,575	523,243	528,305	534,698	586,661	27,147,550
	Supply for Immediate Consumption - Dth													
11	Southwest	631,826	33,547	21,507	23,844	83,852	27,538	1,390,954	100,575	13,243	1,305	7,698	76,661	2,412,550
12	Appalachian - Direct	209,250	202,500	209,250	209,250	189,000	209,250	202,500	209,250	127,500	131,750	131,750	127,500	2,158,750
13	Appalachian - Transport	627,750	607,500	627,750	627,750	567,000	627,750	607,500	627,750	382,500	395,250	395,250	382,500	6,476,250
14	DOM Storage Withdrawa	0	250,000	600,000	1,000,000	750,000	500,000	0	0	0	0	0	0	3,100,000
15	EQT Storage Withdrawal	0	1,700,000	2,800,000	3,300,000	2,900,000	2,300,000	0	0	0	0	0	0	13,000,000
16	Total	1,468,826	2,793,547	4,258,507	5,160,844	4,489,852	3,664,538	2,200,954	937,575	523,243	528,305	534,698	586,661	27,147,550

Pennsylvania Division

Summary of Estimated Purchased Gas Costs
for the Period October 2006 through September 2007

Line No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
		2006						2007						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Purchases													
	Southwest													
1	Quantity - Dth	631,826	33,547	21,507	23,844	83,852	27,538	1,390,954	100,575	13,243	1,305	7,698	76,661	2,412,550
2	Rate - $/Dth	7.46	8.69	9.82	10.59	10.59	10.37	8.52	8.32	8.39	8.47	8.55	8.58	
3	Cost - $	4,715,126	291,521	211,129	252,427	888,174	285,696	11,854,527	836,962	111,092	11,056	65,822	657,798	20,181,330
	Appalachian - Direct													
4	Quantity - Dth	209,250	202,500	209,250	209,250	189,000	209,250	202,500	209,250	127,500	131,750	131,750	127,500	2,158,750
5	Rate - $/Dth	6.93	8.03	9.04	9.73	9.74	9.54	7.88	7.70	7.76	7.84	7.91	7.94	
6	Cost - $	1,450,887	1,626,834	1,892,405	2,036,787	1,840,624	1,997,030	1,596,459	1,612,010	989,878	1,032,755	1,041,978	1,011,808	18,129,455
	Appalachian - Transport													
7	Quantity - Dth	627,750	607,500	627,750	627,750	567,000	627,750	607,500	627,750	382,500	395,250	395,250	382,500	6,476,250
8	Rate - $/Dth	7.28	8.42	9.47	10.19	10.19	9.99	8.26	8.08	8.14	8.22	8.29	8.32	
9	Cost - $	4,567,328	5,114,424	5,943,772	6,393,889	5,778,072	6,269,944	5,019,729	5,069,632	3,112,872	3,247,440	3,276,191	3,181,240	56,974,532
	Dominion Storage Withdrawals													
10	Quantity - Dth		250,000	600,000	1,000,000	750,000	500,000							3,100,000
11	Rate - $/Dth		6.79	6.79	6.79	6.79	6.79							
12	Cost - $		1,696,325	4,071,180	6,785,300	5,088,975	3,392,650							21,034,430
13	Total Purchase Cost - $	10,733,341	8,729,104	12,118,486	15,468,403	13,595,845	11,945,320	18,470,715	7,518,604	4,213,842	4,291,251	4,383,991	4,850,846	116,319,747
	Plus: EQT Storage Withdrawals													
14	Quantity - Dth		1,700,000	2,800,000	3,300,000	2,900,000	2,300,000							13,000,000
15	Rate - $/Dth		7.0493	7.0493	7.0493	7.0493	7.0493							
16	Cost - $	0	11,983,810	19,738,040	23,262,690	20,442,970	16,213,390							91,640,900
	Total Commodity Cost for													
17	Immediate Consumption - $	10,733,341	20,712,914	31,856,526	38,731,093	34,038,815	28,158,710	18,470,715	7,518,604	4,213,842	4,291,251	4,383,991	4,850,846	207,960,647
	Other Purchased Gas Costs - $													
18	Upstream Demand Costs	1,529,534	1,838,062	1,838,062	1,838,062	1,838,062	1,838,062	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	19,897,048
19	Equitrans Demand Costs	3,117,571	3,920,898	3,920,898	3,920,898	3,920,898	3,920,898	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	41,427,487
20	Total Other Costs - $	4,647,105	5,758,960	5,758,960	5,758,960	5,758,960	5,758,960	4,647,105	4,647,105	4,647,105	4,647,105	4,647,105	4,647,105	61,324,535
21	Total Purchased Gas Costs - $	15,380,446	26,471,874	37,615,486	44,490,053	39,797,775	33,917,670	23,117,820	12,165,709	8,860,947	8,938,356	9,031,096	9,497,951	269,285,182
	LESS:													
22	Capacity Release/Standby Credits - $	389,689	537,700	472,519	614,055	979,204	665,949	847,811	489,084	385,292	360,240	356,135	398,981	6,276,658
23	Balancing Credits	434,266	707,981	1,015,565	1,266,361	1,137,671	950,122	576,550	345,777	205,845	216,891	252,197	300,503	7,409,530
24		14,556,490	25,226,193	36,127,402	42,609,637	37,680,899	32,301,599	21,893,459	11,350,848	8,269,810	8,361,424	8,422,765	8,798,467	255,598,994

Pennsylvania Division

Summary of Estimated Firm Capacity Costs on *Equitrans Inc.*
for the Period October 2006 through September 2007

Line No.	Description	2006 October (1)	November (2)	December (3)	2007 January (4)	February (5)	March (6)	April (7)	May (8)	June (9)	July (10)	August (11)	September (12)	Total (13)
	FTS Demand - Non-Storage													
1	Demand Determinant - Dth	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	191,000	2,292,000
2	Demand Rate - $/Dth	5.5105	6.2535	6.2535	6.2535	6.2535	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	-
3	Demand Cost - $	1,052,506	1,194,419	1,194,419	1,194,419	1,194,419	1,194,419	1,052,506	1,052,506	1,052,506	1,052,506	1,052,506	1,052,506	13,339,637
	FTS Demand - NOFT													
4	Demand Determinant - Dth	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	954,540
5	Demand Rate - $/Dth	8.8157	9.5587	9.5587	9.5587	9.5587	9.5587	8.8157	8.8157	8.8157	8.8157	8.8157	8.8157	-
6	Demand Cost - $	701,245	760,347	760,347	760,347	760,347	760,347	701,245	701,245	701,245	701,245	701,245	701,245	8,710,450
	FTS Demand - Storage													
7	Demand Determinant - Dth	21,401	40,000	40,000	40,000	40,000	40,000	21,401	21,401	21,401	21,401	21,401	21,401	349,807
8	Demand Rate - $/Dth	5.5105	6.2535	6.2535	6.2535	6.2535	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	
9	Demand Cost - $	117,930	250,140	250,140	250,140	250,140	250,140	117,930	117,930	117,930	117,930	117,930	117,930	2,076,210
10	Demand Determinant - Dth	82,130	147,546	147,546	147,546	147,546	147,546	82,130	82,130	82,130	82,130	82,130	82,130	1,312,640
11	Demand Rate - $/Dth	5.5105	6.2535	6.2535	6.2535	6.2535	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	
12	Demand Cost - $	452,577	922,679	922,679	922,679	922,679	922,679	452,577	452,577	452,577	452,577	452,577	452,577	7,781,434
	Storage Demand													
13	Capacity Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	480,000
14	Capacity Rate - $/Dth	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	-
15	Capacity Cost - $	73,156	73,156	73,156	73,156	73,156	73,156	73,156	73,156	73,156	73,156	73,156	73,156	877,872
16	Space Determinant - Dth	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	50,181,816
17	Space Rate - $/Dth	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	-
18	Space Cost - $	147,618	147,618	147,618	147,618	147,618	147,618	147,618	147,618	147,618	147,618	147,618	147,618	1,771,416
	Peaking Storage													
19	Capacity Determinant - Dth	147546	147546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	147,546	1,770,552
20	Capacity Rate - $/Dth	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	
21	Capacity Cost - $	269,847	269,847	269,847	269,847	269,847	269,847	269,847	269,847	269,847	269,847	269,847	269,847	3,238,164
22	Space Determinant - Dth	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	102,898,020
23	Space Rate - $/Dth	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	
24	Space Cost - $	302,692	302,692	302,692	302,692	302,692	302,692	302,692	302,692	302,692	302,692	302,692	302,692	3,632,304
25	Total Storage Demand Cost	793,313	793,313	793,313	793,313	793,313	793,313	793,313	793,313	793,313	793,313	793,313	793,313	9,519,756
26	Total Equitrans Demand Costs	3,117,571	3,920,898	3,920,898	3,920,898	3,920,898	3,920,898	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	41,427,487

Docket Number R-00061295
Item 53.64 (a)
Section I, Part B
Sheet 3 of 8

Pennsylvania Division

Summary of Estimated Upstream Pipeline Firm Capacity and Producer Demand Costs
for the Period October 2006 through September 2007

Line No.	Description	2006 October (1)	November (2)	December (3)	2007 January (4)	February (5)	March (6)	April (7)	May (8)	June (9)	July (10)	August (11)	September (12)	Total (13)
	Texas Eastern Transmission Corp													
1	Demand Determinant - Dth	109,207	109,207	109,207	109,207	109,207	109,207	109,207	109,207	109,207	109,207	109,207	109,207	1,310,484
2	Demand Rate - $/Dth	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	
3	Demand Cost - $	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	15,926,052
	Dominion Transmission													
4	Demand Determinant - Dth	6,875	62,000	62,000	62,000	62,000	62,000	6,875	6,875	6,875	6,875	6,875	6,875	358,125
5	Demand Rate - $/Dth	1.5560	4.4230	4.4230	4.4230	4.4230	4.4230	1.5560	1.5560	1.5560	1.5560	1.5560	1.5560	
6	Demand Cost - $	10,698	274,226	274,226	274,226	274,226	274,226	10,698	10,698	10,698	10,698	10,698	10,698	1,446,016
	Dominion Transmission Storage Demand (GSS)													
7	Capacity Determinant - Dth	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	744,000
8	Capacity Rate - $/Dth	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	
9	Capacity Cost - $	116,715	116,715	116,715	116,715	116,715	116,715	116,715	116,715	116,715	116,715	116,715	116,715	1,400,580
10	Space Determinant - Dth	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	37,200,000
11	Space Rate - $/Dth	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	
12	Space Cost - $	44,950	44,950	44,950	44,950	44,950	44,950	44,950	44,950	44,950	44,950	44,950	44,950	539,400
13	Producer Demand	30,000	75,000	75,000	75,000	75,000	75,000	30,000	30,000	30,000	30,000	30,000	30,000	585,000
14	Total Upstream Demand Costs	1,529,534	1,838,062	1,838,062	1,838,062	1,838,062	1,838,062	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	19,897,048

Pennsylvania Division

Summary of Estimated 2006 Storage Injections on Equitrans, Inc.

		2006							
		April	May	June	July	August	September	October	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Beginning Balance								
1	Purchases - Dth	2,500,000	4,000,000	5,500,000	7,000,000	8,500,000	10,000,000	11,500,000	
2	Total Cost - $	23,690,750	32,559,950	41,749,025	51,235,475	61,025,975	71,048,975	81,240,425	
	Southwest Purchases								
3	Purchases - Dth	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	10,500,000
4	Total Costs	8,869,200	9,189,075	9,486,450	9,790,500	10,023,000	10,191,450	10,400,625	67,950,300
	Withdrawals								
5	Purchases - Dth	0	0	0	0	0	0	0	0
6	Total Cost - $	0	0	0	0	0	0	0	0
	Ending Balance								
7	Purchases - Dth	4,000,000	5,500,000	7,000,000	8,500,000	10,000,000	11,500,000	13,000,000	
8	Total Cost - $	32,559,950	41,749,025	51,235,475	61,025,975	71,048,975	81,240,425	91,641,050	
9	Average Cost - $/Dth	8.140	7.591	7.319	7.180	7.105	7.064	7.0493	

Docket Number R-00061295
Item 53.64 (a)
Section I, Part B
Sheet 5 of 8

Pennsylvania Division

Summary of Estimated 2006 Storage Injections on Dominion Transmission

	2006							
	April	May	June	July	August	September	October	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Beginning Balance								
1 Purchases - Dth	0	450,000	900,000	1,350,000	1,800,000	2,250,000	2,700,000	
2 Total Cost - $	0	2,797,064	5,693,149	8,681,240	11,764,400	14,920,043	18,124,062	
Southwest Purchases								
3 Purchases - Dth	450,000	450,000	450,000	450,000	450,000	450,000	400,000	3,100,000
4 Total Costs	2,797,064	2,896,085	2,988,091	3,083,160	3,155,643	3,204,019	2,910,284	21,034,346
Withdrawals								
5 Purchases - Dth	0	0	0	0	0	0	0	0
6 Total Cost - $	0	0	0	0	0	0	0	0
Ending Balance								
7 Purchases - Dth	450,000	900,000	1,350,000	1,800,000	2,250,000	2,700,000	3,100,000	
8 Total Cost - $	2,797,064	5,693,149	8,681,240	11,764,400	14,920,043	18,124,062	21,034,346	
9 Average Cost - $/Dth	6.22	6.33	6.43	6.54	6.63	6.71	6.785	

Pennsylvania Division

Summary of Estimated 2007 Storage Injections on Equitrans, Inc.

	2007							
	April	May	June	July	August	September	October	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Beginning Balance								
1 Purchases - Dth	0	1,875,000	3,750,000	5,625,000	7,500,000	9,375,000	11,250,000	
2 Total Cost - $	0	14,782,031	29,226,563	43,783,594	58,481,250	73,310,156	88,189,688	
Southwest Purchases								
3 Purchases - Dth	1,875,000	1,875,000	1,875,000	1,875,000	1,875,000	1,875,000	1,750,000	13,000,000
4 Total Costs	14,782,031	14,444,531	14,557,031	14,697,656	14,828,906	14,879,531	13,887,563	102,077,250
Withdrawals								
5 Purchases - Dth	0	0	0	0	0	0	0	0
6 Total Cost - $	0	0	0	0	0	0	0	0
Ending Balance								
7 Purchases - Dth	1,875,000	3,750,000	5,625,000	7,500,000	9,375,000	11,250,000	13,000,000	
8 Total Cost - $	14,782,031	29,226,563	43,783,594	58,481,250	73,310,156	88,189,688	102,077,250	
9 Average Cost - $/Dth	7.8838	7.7938	7.7838	7.7975	7.8198	7.8391	7.8521	

Pennsylvania Division

Summary of Estimated 2007 Storage Injections on Dominion Transmission

	2007							
	April	May	June	July	August	September	October	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Beginning Balance								
1 Purchases - Dth	0	450,000	900,000	1,350,000	1,800,000	2,250,000	2,700,000	
2 Total Cost - $	0	3,718,318	7,352,463	11,014,665	14,711,940	18,441,949	22,184,584	
Southwest Purchases								
3 Purchases - Dth	450,000	450,000	450,000	450,000	450,000	450,000	400,000	3,100,000
4 Total Costs	3,718,318	3,634,145	3,662,203	3,697,275	3,730,009	3,742,635	3,326,787	25,511,370
Withdrawals								
5 Purchases - Dth	0	0	0	0	0	0	0	0
6 Total Cost - $	0	0	0	0	0	0	0	0
Ending Balance								
7 Purchases - Dth	450,000	900,000	1,350,000	1,800,000	2,250,000	2,700,000	3,100,000	
8 Total Cost - $	3,718,318	7,352,463	11,014,665	14,711,940	18,441,949	22,184,584	25,511,370	
9 Average Cost - $/Dth	8.26	8.17	8.16	8.17	8.20	8.22	8.230	

Pennsylvania Division

Development of Estimated Purchased Gas Cost
Over/Under Collection for the Pennsylvania Division
For the 9 Months Ending September 2005

Line No.	Description	PGC Sales	PGC Rate	PGC Revenue	Purchased Gas Cost	Over/(Under) Collection
		(1)	(2)	(3)	(4)	(5)
		Mcf	$/Mcf	$	$	$
				(1) x (2)		(3) - (4)
	INTERIM PERIOD					
1	January 2006 *	(94,328)	12.63	(1,191,363)		
	January 2006 *	3,509,083	13.15	46,144,447		
	Total January			44,953,084	50,250,537	(5,297,453)
2	February *	3,863,855	13.15	50,809,696	46,837,985	3,971,711
3	March	3,273,287	13.15	43,043,724	36,642,778	6,400,946
4	April	1,965,966	13.15	25,852,453	17,260,546	8,591,907
5	May	837,474	13.15	11,012,783	9,904,713	1,108,070
6	June	467,378	13.15	6,146,021	7,522,029	(1,376,008)
7	July	471,900	13.15	6,205,485	7,681,912	(1,476,427)
8	August	477,610	13.15	6,280,572	7,780,342	(1,499,770)
9	September	524,025	13.15	6,890,929	8,119,251	(1,228,322)
10	Total	15,296,251		246,147,831	192,000,094	9,194,653

* Actual

Docket Number R-00061295
Item 53.64 (a)
Section I, Part C
Sheet 1 of 7

Docket No. R-00061295
Item 53.64(a)
Section I, Part C
Sheet 2 of 7

Equitable Gas Company
Pennsylvania Division

Summary of January and February 2006 Actual Purchased Gas Costs
(Total Costs)

Line No.	Description	January (1)	February (2)
	COMMODITY		
	Appalachian Purchases		
1	Purchases - Dth	822,614	1,006,219
2	Appalachian Cost	11,642,259	8,274,585
	Upstream Pipeline Supply		
3	Purchases - Dth	2,061,342	1,457,686
4	Total Cost	27,182,478	17,238,881
5	Cash In	2,093	949,510
6	Storage Withdrawals - *Dth*	942,954	1,756,154
7	Storage Withdrawal Costs	8,575,649	16,239,687
8	Total Commodity Cost of Gas	47,402,479	42,702,663
	Other Purchased Gas Costs		
9	Demand	5,499,468	5,525,085
10	Total Current Month Gas Cost	52,901,947	48,227,748
11	Less Credits to PGC	2,651,410	1,389,764
12	Total 1307(f) Gas Cost	50,250,537	46,837,985

Equitable Gas Company
Pennsylvania Division

Summary of January and February 2006 Actual Demand Costs

Line No.	Description	January (1)	February (2)
	Equitrans FTS - Storage Demand		
1	Winter		
2	Summer	2,100,797	2,101,614
3	Total	2,100,797	2,101,614
	Equitrans FTS - Non Storage Demand		
4	Winter		
5	Summer	1,444,559	1,444,559
6	Total	1,444,559	1,444,559
	Equitrans Storage Demand		
7	Daily Capacity	421,241	421,241
8	Space	316,622	316,622
9	Total	737,863	737,863
	Texas Eastern DEMAND		
10	Total	1,327,173	1,318,874
	Producer DEMAND		
11	Total	0	0
	CIPCO DEMAND		
12	Total		
	Dominion DEMAND		
13	Total	435,891	435,891
14	Less Capacity Release	546,815	513,716
15	Total Demand Costs	5,499,468	5,525,085

Pennsylvania Division

Summary of Estimated PGC Sales and Supply Requirements
for the Period March 2006 through September 2006

Line No.	Description	March (1)	April (2)	May (3)	June (4)	July (5)	August (6)	September (7)	Total (8)
	PGC Sales - Mcf								
1	Residential	2,736,776	1,639,446	669,742	354,297	363,505	362,726	402,456	6,528,948
2	Small Commercial	313,552	190,321	96,037	63,274	60,993	65,152	68,803	858,132
3	Small Industrial	1,428	903	443	305	270	265	307	3,921
4	Large Commercial	215,531	131,397	69,089	47,742	45,504	47,784	50,895	607,942
5	Large Industrial	6,000	3,899	2,163	1,760	1,628	1,683	1,564	18,697
6	Total PGC Sales	3,273,287	1,965,966	837,474	467,378	471,900	477,610	524,025	8,017,640
7	Company Use	7,149	7,149	3,209	1,811	1,829	1,831	2,433	25,411
8	UFG	172,655	103,848	44,246	24,694	24,933	25,234	27,708	423,318
	Total Demand - Mcf	3,453,091	2,076,963	884,929	493,883	498,662	504,675	554,166	8,466,369
9	BTU Conversion	1.060	1.060	1.060	1.060	1.060	1.060	1.060	
10	Total Demand - Dth	3,660,276	2,201,581	938,025	523,516	528,582	534,956	587,416	8,974,351
	Total Supply for Immediate Consumption								
11	Southwest	1,216,706	1,658,011	376,336	0	0	0	0	3,251,053
12	Appalachian - Direct	21,000	21,000	21,700	21,000	21,700	21,700	21,000	149,100
13	Appalachian - Transport	522,570	522,570	539,989	502,516	506,882	513,256	566,416	3,674,198
14	DOM Storage Withdrawals	0	0	0	0	0	0	0	0
15	EQT Storage Withdrawals	1,900,000	0	0	0	0	0	0	1,900,000
16	Total	3,660,276	2,201,581	938,025	523,516	528,582	534,956	587,416	8,974,351

Equitable Gas Company
Pennsylvania Division

Summary of Estimated Purchased Gas Costs for the
for the Period March 2006 through September 2006

Line No.	Description	March (1)	April (2)	May (3)	June (4)	July (5)	August (6)	September (7)	Total (8)
	Purchases								
	Southwest								
1	Quantity - Dth	1,216,706	1,658,011	376,336	0	0	0	0	3,251,053
2	Rate - $/Dth	8.12	6.32	6.56	6.79	7.02	7.19	7.32	
3	Cost - $	9,874,130	10,477,187	2,470,486	0	0	0	0	22,821,803
	Appalachian - Direct								
4	Quantity - Dth	21,000	21,000	21,700	21,000	21,700	21,700	21,000	149,100
5	Rate - $/Dth	7.49	5.91	6.13	6.32	6.53	6.68	6.79	
6	Cost - $	157,370	124,169	132,935	132,810	141,636	144,999	142,680	976,599
	Appalachian - Transport								
7	Quantity - Dth	522,570	522,570	539,989	502,516	506,882	513,256	566,416	3,674,198
8	Rate - $/Dth	7.88	6.22	6.44	6.64	6.85	7.01	7.12	
9	Cost - $	4,116,768	3,248,138	3,475,231	3,336,808	3,472,883	3,599,224	4,032,906	25,281,958
	Equitrans Storage Withdrawals								
10	Quantity - Dth	1,900,000							1,900,000
11	Rate - $/Dth	9.48							
12	Cost - $	18,004,970	0	0	0	0	0	0	18,004,970
	Dominion Storage Withdrawals								
13	Quantity - Dth	0							0
14	Rate - $/Dth	8.84							
15	Cost - $	0	0	0	0	0	0	0	0
16	Total Commodity Cost for Immediate Consumption - $	32,153,238	13,849,494	6,078,652	3,469,618	3,614,519	3,744,223	4,175,586	67,085,330
	Other Purchased Gas Costs - $								
17	Upstream Demand Costs	1,838,062	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	11,015,266
18	Equitrans Demand Costs	4,278,223	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	22,983,650
19	Total Other Costs	6,116,285	4,647,105	4,647,105	4,647,105	4,647,105	4,647,105	4,647,105	33,998,916
20	Total Purchased Gas Costs for Immediate Consumption	38,269,523	18,496,599	10,725,757	8,116,723	8,261,624	8,391,328	8,822,691	101,084,246
	LESS:								
21	Capacity Release/Standby Credits	676,624	659,503	475,287	388,849	363,021	358,789	402,937	3,324,989
22	Balancing Credits	950,122	576,550	345,777	205,845	216,691	252,197	300,503	2,847,685
23	Total 1307(f) Gas Costs	36,642,778	17,260,546	9,904,713	7,522,029	7,681,912	7,780,342	8,119,251	94,911,572

Pennsylvania Division

Summary of Estimated Firm Capacity Costs from Equitrans, Inc.
for the Period March 2006 through September 2006

Line No.	Description	March (1)	April (2)	May (3)	June (4)	July (5)	August (6)	September (7)	Total (8)
	FTS Demand - Non-Storage								
1	Demand Determinant - Dth	191,000	191,000	191,000	191,000	191,000	191,000	191,000	1,337,000
2	Demand Rate - $/Dth	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	
3	Demand Cost - $	1,194,419	1,052,506	1,052,506	1,052,506	1,052,506	1,052,506	1,052,506	7,509,452
	FTS Demand - NOFT								0
4	Demand Determinant - Dth	94,742	79,545	79,545	79,545	79,545	79,545	79,545	572,012
5	Demand Rate - $/Dth	9.5587	8.8157	8.8157	8.8157	8.8157	8.8157	8.8157	
6	Demand Cost - $	905,610	701,245	701,245	701,245	701,245	701,245	701,245	5,113,079
	FTS Demand - Storage								
	Base Load Services								
7	Demand Determinant - Dth	40,000	21,401	21,401	21,401	21,401	21,401	21,401	168,406
8	Demand Rate - $/Dth	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	
9	Demand Cost - $	250,140	117,930	117,930	117,930	117,930	117,930	117,930	957,721
	Peaking Services								
10	Demand Determinant - Dth	190,324	82,130	82,130	82,130	82,130	82,130	82,130	683,104
11	Demand Rate - $/Dth	6.2535	5.5105	5.5105	5.5105	5.5105	5.5105	5.5105	
12	Demand Cost - $	1,190,191	452,577	452,577	452,577	452,577	452,577	452,577	3,905,655
	Storage Demand								
	Base Load Services								
13	Capacity Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	280,000
14	Capacity Rate - $/Dth	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	
15	Capacity Cost - $	73,156	73,156	73,156	73,156	73,156	73,156	73,156	512,092
16	Space Determinant - Dth	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	4,181,818	29,272,726
17	Space Rate - $/Dth	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	
18	Space Cost - $	147,618	147,618	147,618	147,618	147,618	147,618	147,618	1,033,327
	Peaking Services								
19	Capacity Determinant - Dth	190325	147,546	147,546	147,546	147,546	147,546	147,546	1,075,601
20	Capacity Rate - $/Dth	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	1.8289	
21	Capacity Cost - $	348,085	269,847	269,847	269,847	269,847	269,847	269,847	1,967,167
22	Space Determinant - Dth	4,787,646	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	8,574,835	56,236,656
23	Space Rate - $/Dth	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	
24	Space Cost - $	169,004	302,692	302,692	302,692	302,692	302,692	302,692	1,985,156
25	Total Storage Demand Cost - $	737,863	793,313	793,313	793,313	793,313	793,313	793,313	5,497,742
26	Total Demand Costs - $	4,278,223	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	3,117,571	22,983,650

Pennsylvania Division

Summary of Estimated Upstream Pipeline Firm Capacity and Producer Demand Costs
for the Period March 2006 through September 2006

Line No.	Description	March (1)	April (2)	May (3)	June (4)	July (5)	August (6)	September (7)	Total (8)
	Texas Eastern Transmission Corp								
1	Demand Determinant - Dth	109,207	109,207	109,207	109,207	109,207	109,207	109,207	764,449
2	Demand Rate - $/Dth	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	12.1528	
3	Demand Cost - $	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	1,327,171	9,290,197
	Dominion Transmission (FT)								
4	Demand Determinant - Dth	62,000	6,875	6,875	6,875	6,875	6,875	6,875	103,250
5	Demand Rate - $/Dth	4.4230	1.5560	1.5560	1.5560	1.5560	1.5560	1.5560	
6	Demand Cost - $	274,226	10,698	10,698	10,698	10,698	10,698	10,698	338,414
	Dominion Transmission (GSS)								
7	Capacity Determinant - Dth	62,000	62,000	62,000	62,000	62,000	62,000	62,000	434,000
8	Capacity Rate - $/Dth	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	1.8825	
9	Capacity Cost - $	116,715	116,715	116,715	116,715	116,715	116,715	116,715	817,005
10	Space Determinant - Dth	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	21,700,000
11	Space Rate - $/Dth	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	
12	Space Cost - $	44,950	44,950	44,950	44,950	44,950	44,950	44,950	314,650
13	Producer Demand	75,000	30,000	30,000	30,000	30,000	30,000	30,000	255,000
14	Total Upstream Demand Cost - $	1,838,062	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	1,529,534	11,015,266

Pennsylvania Division
Calculation of Actual Gas Cost Over/(Under) Collections
for the Period January 2005 through December 2005

Line No.	Description	Sales	PGC Rate	PGC Revenue	Purchased Gas Cost	Over/(Under) Collection	Over/(Under) Included In PGC 05	Over/(Under) to be Included in PGC 2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Mcf	$/Mcf	$	$	$	$	$
				(1) x (2)		(3) - (4)		
1	January	4,595,578	$ 9.48	43,566,079	48,087,526	(4,521,447)	(4,521,448)	0
2	February	3,765,152	$ 9.48	35,693,645	31,937,606	3,756,039	3,756,038	0
3	March	3,756,906	$ 9.48	35,615,468	38,074,676	(2,459,208)	(2,459,208)	0
4	April	(212,078)	$ 9.48	(2,010,499)				
5	April	1,850,123	$ 10.13	18,741,745				
6	Total April	1,638,045		16,731,246	13,356,292	3,374,954	3,374,954	0
7	May	1,091,090	$ 10.13	11,052,742	13,044,742	(1,992,000)	(1,992,000)	0
8	June	363,386	$ 10.13	3,681,102	10,901,908	(7,220,806)	(7,220,806)	0
9	July	451,326	$ 10.13	4,571,933	10,570,889	(5,998,956)	(5,998,956)	0
10	August	439,571	$ 10.13	4,452,852	3,660,951	791,901	791,901	0
11	September	413,448	$ 10.13	4,188,232	2,405,992	1,782,240	(830,538)	2,612,778
12	October	14,546	$ 10.13	147,351				0
13	October	1,267,204	$ 12.63	16,004,787				0
14	Total October	1,281,750		16,152,138	16,563,403	(411,265)		(411,265)
15	November	2,306,345	$ 12.63	29,129,139	47,829,564	(18,700,425)		(18,700,425)
16	December	4,087,255	$ 12.63	51,622,036	58,521,366	(6,899,330)		(6,899,330)
17	Total	24,189,853		256,456,612	294,954,916	(38,498,304)	(15,100,063)	(23,398,241)

Equitable Gas Company
Pennsylvania Division

Summary of 2005 Actual Purchased Gas Costs
(Total Costs)

Line No.	Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	COMMODITY													
	Appalachian Purchases													
1	Purchases - Dth	1,139,511	1,227,320	626,787	102,130	488,532	697,759	986,585	189,240	(14,108)	848,939	1,280,052	1,275,090	8,847,837
2	Appalachian Cost	5,510,245	8,120,370	1,300,070	(502,561)	4,160,689	7,707,236	7,344,319	1,790,680	648,407	9,193,155	19,126,806	19,011,664	83,411,080
	Upstream Pipeline Supply													
3	Purchases - Dth	1,088,764	785,756	454,666	1,422,280	1,144,927			3,406	119,916	350,074	1,276,400	547,158	7,193,347
4	Total Cost	12,801,064	3,431,953	14,599,337	9,705,304	5,731,033		3,129	(1,322,161)	863,391	4,116,523	19,718,658	11,676,979	81,325,211
	Cash In													
5	Total Cost	277,085	176,280	216,048	0	114,904	20,036	16,327	0	0	127,269	122,107	1,072	1,071,127
6	Total Commodity Cost of Purchases	18,588,394	11,728,603	16,115,455	9,202,742	10,006,627	7,727,272	7,363,774	468,519	1,511,799	13,436,947	38,967,570	30,689,715	165,807,417
7	Storage Withdrawals - Dth	3,808,659	2,448,455	2,652,267	192,849	0	0	0	0	0	0	568,200	2,550,691	12,221,121
8	Storage Commodity Costs	24,787,180	15,883,792	17,250,449	1,261,140	0	0	0	0	0	0	5,014,618	23,783,249	87,980,429
9	Storage Withdrawal Costs	59,863	38,674	41,578	2,989	0	0	0	0	0	0	0	38,982	182,085
10	Total Storage Costs	24,847,043	15,922,466	17,292,028	1,264,129	0	0	0	0	0	0	5,014,618	23,822,231	88,162,514
11	Total Commodity Cost of Gas	43,435,437	27,651,069	33,407,483	10,466,871	10,006,627	7,727,272	7,363,774	468,519	1,511,799	13,436,947	43,982,188	54,511,946	253,969,931
	Other Purchased Gas Costs													
12	Demand	5,014,741	5,020,211	5,038,911	3,268,729	3,269,564	3,275,183	3,273,627	3,275,508	3,281,142	3,624,509	5,532,646	5,500,005	49,374,776
13	Total Current Month Gas Cost	48,450,177	32,671,279	38,446,394	13,735,600	13,276,191	11,002,455	10,637,401	3,744,027	4,792,941	17,061,456	49,514,834	60,011,952	303,344,707
	Credits to PGC													
14	Standby Service	362,651	733,673	371,718	379,309	231,449	91,952	66,512	63,015	69,097	113,744	227,398	165,371	2,875,888
15	Cash Out	0	0	0	0	0	8,595	0	20,061	67,852	29,720	623,360	150,135	899,723
16	Off system/Cap release sharing										36,495	242,197	142,540	421,232
17	PBR / Balancing credit	0								2,250,000	318,094	592,314	1,032,540	4,192,948
18	Total Credits to PGC	362,651	733,673	371,718	379,309	231,449	100,547	66,512	83,076	2,386,949	498,053	1,685,269	1,490,586	8,389,791
19	Total 1307(f) Gas Cost	48,087,526	31,937,606	38,074,676	13,356,292	13,044,742	10,901,908	10,570,889	3,660,951	2,405,992	16,563,403	47,829,564	58,521,366	294,954,916

Equitable Gas Company
Pennsylvania Division

Summary of 2005 Actual Purchased Gas Costs
(Demand Costs)

Line No.	Description	January (1)	February (2)	March (3)	April (4)	May (5)	June (6)	July (7)	August (8)	September (9)	October (10)	November (11)	December (12)	Total (13)
	Equitrans FTS - Storage Demand													
1	Total	1,288,083	1,288,083	1,288,083	132,561	132,561	132,561	132,561	132,561	132,561	132,561	1,190,191	1,190,191	7,172,557
2	No-Notice	-									350,513	909,791	917,804	2,178,108
3	Total	1,288,083	1,288,083	1,288,083	132,561	132,561	132,561	132,561	132,561	132,561	483,074	2,099,982	2,107,995	9,350,664
	Equitrans FTS - Non Storage Demand													
4	Winter	1,444,559	1,444,559	1,444,559	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,444,559	1,444,559	15,400,837
5	Summer	-												0
6	Total	1,444,559	1,444,559	1,444,559	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,168,292	1,444,559	1,444,559	15,400,837
	Equitrans Storage Demand													
7	Daily Capacity	449,871	449,871	449,871	421,241	421,241	421,241	421,241	421,241	421,241	421,241	421,241	421,241	5,140,785
8	Space	374,392	374,392	374,392	316,622	316,622	316,622	316,622	316,622	316,622	316,622	316,622	316,622	3,972,774
9	Total	824,263	824,263	824,263	737,863	737,863	737,863	737,863	737,863	737,863	737,863	737,863	737,863	9,113,560
10	Total Equitrans	3,556,905	3,556,905	3,556,905	2,038,716	2,038,716	2,038,716	2,038,716	2,038,716	2,038,716	2,389,229	4,282,404	4,290,417	33,865,062
	CIPCO DEMAND													
11	Total	15,365	15,365	15,365										46,095
	Texas Eastern DEMAND													
12	Total	1,333,289	1,329,685	1,329,685	1,329,685	1,329,685	1,329,685	1,329,685	1,329,030	1,329,030	1,329,030	1,329,030	1,327,173	15,954,693
	Producer DEMAND													
13	Total	0	0	0	0	0	0	0	0	0				0
	Dominion Trans. DEMAND													
14	Total	492,826	487,990	514,408	172,346	172,346	172,346	172,346	172,346	172,346	172,346	435,891	435,891	3,573,426
	Capacity Release													
15	Equitrans	257,712	256,737	253,754	154,023	151,357	150,365	149,089	147,711	146,646	146,986	236,973	258,767	2,310,120
16	Dominion											154,805	176,505	331,310
17	Columbia Gas													
18	Texas Eastern	125,931	112,997	123,697	117,995	119,826	115,200	118,031	116,874	112,304	119,110	122,900	118,204	1,423,070
19	CIPCO													0
20	Total	383,644	369,734	377,451	272,018	271,183	265,565	267,120	264,584	258,950	266,097	514,678	553,476	4,064,500
21	Total Demand Costs	5,014,741	5,020,211	5,038,911	3,268,729	3,269,564	3,275,183	3,273,627	3,275,508	3,281,142	3,624,509	5,532,646	5,500,005	49,374,776

Pennsylvania Division

Summary of Actual Storage Activity
2005

	January	February	March	April	May	June	July	August	September	October	November	December	Total
	2005												
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Beginning Balance													
1 Purchases - Dth	9,785,831	5,977,172	3,528,717	872,950	1,715,966	3,308,497	4,698,380	6,303,443	7,714,133	9,146,490	10,423,791	10,254,357	
2 Total Cost - $	63,662,231	38,875,051	22,991,259	5,716,380	12,829,732	24,912,018	34,781,347	44,452,465	57,594,529	72,424,993	89,503,305	95,636,569	
Upstream Pipeline Service													
3 Purchases - Dth	0	0	(3,500)	1,035,865	1,592,531	1,389,883	1,605,063	1,410,690	1,432,357	1,277,301	398,766	0	10,138,956
4 Commodity Cost	0	0	(24,430)	8,374,493	12,082,285	9,869,329	9,671,118	13,142,064	14,830,464	17,078,312	11,147,882	44,647	96,216,164
Total Storage Injections													
5 Purchases - Dth	0	0	(3,500)	1,035,865	1,592,531	1,389,883	1,605,063	1,410,690	1,432,357	1,277,301	398,766	0	10,138,956
6 Total Costs	0	0	(24,430)	8,374,493	12,082,285	9,869,329	9,671,118	13,142,064	14,830,464	17,078,312	11,147,882	44,647	96,216,164
Withdrawals													
7 Purchases - Dth	3,808,659	2,448,455	2,652,267	192,849	0	0	0	0	0	0	568,200	2,550,691	12,221,121
8 Total Cost - $	24,787,180	15,883,792	17,250,449	1,261,140	0	0	0	0	0	0	5,014,618	23,783,249	87,980,429
Ending Balance													
9 Purchases - Dth	5,977,172	3,528,717	872,950	1,715,966	3,308,497	4,698,380	6,303,443	7,714,133	9,146,490	10,423,791	10,254,357	7,703,666	
10 Total Cost - $	38,875,051	22,991,259	5,716,380	12,829,732	24,912,018	34,781,347	44,452,465	57,594,529	72,424,993	89,503,305	95,636,569	71,897,967	
11 Average Cost - $/Dth	6.5039	6.5155	6.5483	7.4767	7.5297	7.4028	7.0521	7.4661	7.9183	8.5864	9.3264	9.3330	

SUPPLEMENT NO.

TO

GAS - PA. P.U.C. NO. 22

EQUITABLE GAS COMPANY

A DIVISION OF EQUITABLE RESOURCES, INC.

SCHEDULE OF RATES, RULES AND REGULATIONS

FOR

GAS SERVICE IN

CITY OF PITTSBURGH

AND TERRITORY ADJACENT THERETO

(For Lists of Communities Served, see Page No. 4)

ISSUED: EFFECTIVE: October 1, 2006

Tariff Supplement filed to Decrease

Purchased Gas Cost Rate in

2006 1307(f) Proceeding at Docket No. R-00061295

Issued

By

D. L. FRUTCHEY
SENIOR VICE PRESIDENT
EQUITABLE GAS COMPANY
225 North Shore Drive
PITTSBURGH, PA 15212-5861

CHANGE IN RATES AND TARIFF MODIFICATION

		Rules and Regulations, page 35
Rate RS	-	Residential Service; page 40.
Rate GSS	-	General Service Small; page 41.
Rate GSL	-	General Service Large; page 42.
Rate FDS		Firm Delivery Service; pages 61 and 62
Rate DDS		Daily Delivery Service; page 67
Rate FPS		Firm Pooling Service; pages 69 and 70
	-	Standby Service; pages 78 and 79.
Rider A	-	Purchased Gas Cost; page 92.
Rider B	-	Transportation Migration Rider; page 94.

RULES AND REGULATIONS - (Continued)

(d) If a Pool Administrator initiates or becomes a party to any of the events or actions described in (c), or if a Pool Administrator's credit rating is downgraded below B+, Pool Administrator must provide written notification to the Company within two working days of any such initiated or imposed action.

(e) If a Pool Administrator has a relationship with the Company, then the Pool Administrator: (i) must have paid its account in the past according to the terms of the service agreement; and (ii) must have no delinquent balances outstanding for services rendered by the Company.

Credit Enhancements:

(i) A security deposit equal to the aggregated pool Maximum Daily Quantity times the sum of the highest Midpoint price published in Platts, Gas Daily publication, under the heading Appalachia, Dominion, South Point for the most recent month available times 60 days. (C)

(ii) A payment in advance equal to the amount calculated in (i).

(iii) An irrevocable letter of credit drawn upon a bank acceptable to the Company.

11.21 Acceptable Business Practices

In addition to the creditworthiness criteria Pool Administrators must also adhere to the following business practices.

(a) The bills rendered by the Pool Administrator will be clear and in plain language and shall meet the billing information requirements of Chapter 56 of the Commission's regulations. Bills rendered by a Pool Administrator shall contain a statement directing the ratepayer to "register any question or complaint about the bill prior to the due date", as directed by Commission regulations and shall contain the Company's and the Pool Administrator's telephone numbers where the customer may initiate an inquiry or complaint. Bills must also include the phone number of the Commission's customer hot line.

(b) Pool Administrators shall provide customers with minimum payment periods required by the Commission's regulations; i.e. residential customers shall have 20 days to pay and commercial customers shall have 15 days. The Pool Administrator shall notify the customer with adequate notice of the consequences of failure to pay.

(c) Pool Administrators must establish and use customer complaint procedures and respond to complaints in a timely fashion.

(C) Indicates Change.

RATE RS - RESIDENTIAL SERVICE

APPLICABILITY

These rates shall be applicable throughout the territory served by the Company.

AVAILABILITY

Available at one location for the total gas requirements of any residential customer account.

RATE

The monthly charge for each customer served at each location under this rate schedule shall be the sum of the following:

Monthly Service Charge:	$11.65 per meter	
Natural Gas Supply Charge:	$10.72 per Mcf	(D)
Natural Gas Delivery Charge:	$3.263 per Mcf	(D)

Customers returning from delivery service in accordance with Rider B

Natural Gas Delivery Charge:	$2.523 per Mcf	(D)

LATE PAYMENT CHARGE

If payment of bill has not been received within twenty days from date of mailing, a Late Payment Charge of 1.5% per month, will be added to the unpaid balance each month until the entire bill is paid.

MINIMUM CHARGES

The minimum monthly payment shall be the Monthly Service Charge.

SURCHARGES AND RIDERS

Gas sold under this schedule is also subject to applicable Surcharges and Riders of this Tariff.

RULES AND REGULATIONS

The Company's Rules and Regulations in effect from time to time where not inconsistent with any specific provision herein are a part of this rate schedule.

(D) Indicates Decrease.

RATE GSS - GENERAL SERVICE SMALL

APPLICABILITY

These rates shall be applicable throughout the territory served by the Company.

AVAILABILITY

Available for the total gas requirements at each service location of a commercial or industrial customer who the Company estimates will use 1,000 MCF or less in a twelve month period at that service location.

RATE

The monthly charge for each customer at each location served under this rate schedule will be the following:

Monthly Service Charge:

Annual Throughput < 500	$17.00 per meter	
Annual Throughput 500 - 1,000	$28.00 per meter	
Natural Gas Supply Charge:	$10.72 per Mcf	(D)
Natural Gas Delivery Charge:	*$3.297 per Mcf*	(D)

Customers returning from delivery service in accordance with Rider B

Natural Gas Delivery Charge:	*$2.557 per Mcf*	(D)

LATE PAYMENT CHARGE

If payment of bill has not been received within fifteen days from date of mailing, a Late Payment Charge of 1.5% per month will be added to the unpaid balance each month until the entire bill is paid.

MINIMUM CHARGES

The minimum monthly payment shall be the Monthly Service Charge.

SURCHARGES AND RIDERS

Gas sold under this schedule is also subject to applicable Surcharges and Riders of this Tariff.

RULES AND REGULATIONS

The Company's Rules and Regulations in effect from time to time where not inconsistent with any specific provision herein are a part of this rate schedule.

(D) Indicates Decrease.

RATE GSL - GENERAL SERVICE LARGE

APPLICABILITY

These rates shall be applicable throughout the territory served by the Company.

AVAILABILITY

Available for the total gas requirements at each service location of an industrial or commercial customer who the Company estimates will use more than 1,000 Mcf in a twelve month period at that service location.

RATE

Monthly Service Charge:

Annual Throughput 1,001 - 4,999	$ 75.00 per meter	
Annual Throughput 5,000 - 25,000	$150.00 per meter	
Annual Throughput > 25,000	$800.00 per meter	
Natural Gas Supply Charge:	$10.72 per Mcf	(D)
Natural Gas Delivery Charge:	$3.10 per Mcf	(D)

Customers returning from delivery service in accordance with Rider B

Natural Gas Delivery Charge:	$2.36 per Mcf	(D)

LATE PAYMENT CHARGE

If payment of bill has not been received within fifteen days from date of mailing, a Late Payment Charge of 1.5% will be added to the unpaid balance each month until the entire bill is paid.

MINIMUM CHARGE

The minimum monthly payment shall be the Monthly Service Charge.

SURCHARGES AND RIDERS

Gas sold under this schedule is also subject to applicable Surcharges and Riders of this Tariff.

RULES AND REGULATIONS

The Company's Rules and Regulations in effect from time to time where not inconsistent with any specific provision herein are a part of this rate schedule.

(D) Indicates Decrease.

RATE FDS - FIRM DELIVERY SERVICE

APPLICABILITY

These rates shall be applicable throughout the territory served by the Company, i.e., Equitable and Apollo Districts

AVAILABILITY

Service under this rate schedule is available for resale service and to any essential human needs customer and to any other customer who consumes no more than 5,000 Mcf annually where the customer's full commodity requirements are supplied through a single aggregation pool pursuant to the Company's Firm Pooling Service (FPS).

RATE

The applicable rate for each district shall be determined by negotiation between the Company and the customer and shall not exceed the rates set forth below plus riders applicable to this service:

Monthly Service Charge:

Residential	$ 11.65 per meter
Commercial and Industrial:	
Annual Throughput < 500	$ 17.00 per meter
Annual Throughput 500 -.1,000	$ 28.00 per meter
Annual Throughput 1,001 - 4,999	$ 75.00 per meter

(C)
(C)

Delivery Charge:

Residential Service	$ 2.523 per Mcf
Small Commercial, Industrial and Resale	$ 2.557 per Mcf
Large Commercial and Industrial	$ 2.360 per Mcf

Balancing Charge:
Pursuant to Special Provision (a): $ 0.18 per Mcf

MINIMUM CHARGE

The minimum monthly payment shall be the Monthly Service charge.

(C) Indicates Change.

RATE FDS - FIRM DELIVERY SERVICE (CONTINUED)

SPECIAL PROVISIONS

(a) The Balancing Charge includes the cost of the resources needed by the Company to balance its system. This charge is collected from all delivery service customers, with the Company retaining the right to waive this charge, in whole or in part, for customers with competitive options.

RULES AND REGULATIONS

Service under this rate schedule is subject to the Additional Rules Applicable to All Delivery Services and other applicable rules contained in this tariff. Customers served under this rate schedule are subject to all applicable surcharges and riders including:

Transportation Migration Rider B
Transition Cost Surcharge Rider C

Residential: (C)
Universal Service and Energy Conservation Rider D

(C) Indicates Change

RATE DDS- DAILY DELIVERY SERVICE (CONTINUED)

RATE

The applicable rate shall be determined by negotiation between the Company and the customer and shall not exceed the rates set forth below plus riders applicable to this service:

Monthly Service Charge:		
Commercial and Industrial:		(C)
Annual Throughput 5,000 - 25,000	$150.00 per meter	
Annual Throughput > 25,000	$800.00 per meter	
Delivery Charge:		
Resale Service	$ 2.557 per Mcf	
Large Commercial and Industrial	$ 2.360 per Mcf	
Balancing Charge:		
Pursuant to Special Provision (a)	$ 0.18 per Mcf	

Customers served under this rate schedule are subject to all applicable surcharges and riders including:

Transportation Migration Rider B
Transition Cost Surcharge Rider C

SPECIAL PROVISIONS

(a) The Balancing Charge includes the cost of the resources needed by the Company to balance its system. This charge is collected from all delivery service customers, with the Company retaining the right to waive this charge, in whole or in part, for customers with competitive options.

BALANCING CHARGES

Daily Balancing

A daily imbalance will exist when (a) a customer's consumption in a day falls short of the daily gas supply nominated (daily supply excess), or (b) a customer's consumption in a day exceeds the daily supply nominated (daily supply shortfall).

(1) All daily supply excess or shortfall greater than 3.5% of the customer's consumption for a day shall be charged a $0.25 per Mcf penalty.
(2) A daily supply excess greater than 3.5% will be Cashed-In at 85% of the Midpoint price published in Platts, Gas Daily publication, under the heading Appalachia, Dominion, South Point on the day the excess occurs.

(C) Indicates Change.

RATE FPS - FIRM POOLING SERVICE

TERMS AND CONDITIONS

1. AVAILABILITY

Service under this rate schedule is available to anyone who aggregates a minimum of 50 customers or 5,000 Mcf annually, who demonstrates to the Company's satisfaction that it has met the creditworthiness and fitness standards defined in the Rules and Regulations of this tariff, and who has entered into a Firm Pooling Service Agreement with the Company.

2. TYPE OF SERVICE

This is a customer aggregation service whereby a creditworthy third party, the Pool Administrator, takes assignment on behalf of a FDS customer of the customer's nomination and balancing responsibilities and, under separate contractual agreement with the Company, aggregates the customer's gas deliveries and consumption with those of other FDS customers for the purposes of calculating imbalances on the Company's system.

3. SERVICE CONDITIONS

3.1 Assignment of Upstream Capacity

The Company will assign the following upstream firm pipeline capacity, excluding no-notice service, to the Pool Administrator in a two-tiered approach: firm transportation on the Company's upstream transportation pipeline, Texas Eastern Transmission Corporation ("TETCo"); firm transportation on Equitrans L.P. ("Equitrans") with primary receipt points at interconnections with TETCo; and storage related firm transportation on Equitrans. Capacity will be assigned on behalf of each customer of the Pool Administrator's FPS Pool based on the Company's determination of peak design day consumption of the customer. The two tiers of capacity assignment are as follows:

(C)

(i) Pools with MDQs less than 1,000 Dth per day

No capacity will be assigned. The firm standby charge will apply to the Pool consumption and be billed to the Pool Administrator. The Pool Administrator will have the option of (1) purchasing and delivering supplies under its own supply contracts, or (2) purchasing gas supplies on an interruptible basis from the Company.

(C) Indicates Change

RATE FPS - FIRM POOLING SERVICE (CONTINUED)

(ii) Pools with MDQs greater than or equal to 1,000 Dth per day (C)

The Pool Administrator will be assigned firm transportation and firm storage capacity on a pro-rata basis. However, the pool administrator may elect, subject to the Company's approval, assignment on a non-discriminatory basis of other than a pro-rata allocation.

(C) Indicates Change

STANDBY SERVICE.

Firm Standby Service is mandatory for customers served under Rate CSF and for essential human needs customers served under any delivery service except where the customer has Alternate Fuel Capability, or the customer has received an assignment of Company's upstream pipeline capacity. Firm Standby Service is optional for other customers upon request. For a customer who does not receive Firm Standby Service, daily consumption in excess of daily deliveries on customer's behalf, in excess of customer's Maximum Daily Firm Requirement (MDFR) or in excess of a customer's Maximum Daily Quantity (MDQ) is interruptible.

Firm Standby Service is available pursuant to the following terms and conditions and subject to availability of sufficient gas supply and system capacity.

1. Customers who require natural gas service through a single meter of 20,000 Mcf or more annually:

   Customers who desire Firm Standby Service must also nominate a MDFR for the entire year. MDFR nominations must be specified in the customer's service agreement. (C)

   The MDFR nominations must be at a level which is reasonably sufficient to meet the customer's peak winter season demand. The Company reserves the right to require revisions to nominations which it has determined are insufficient. The Company at its discretion may allow customers to nominate MDFRs which are below anticipated winter season peak demands and in such cases may require separate piping and/or metering to segregate the customer's firm and interruptible loads and may require the customer to reimburse the Company for any cost incurred in making the necessary modifications. (C)

2. Customers who require annual natural gas service through a single meter of less than 20,000 Mcf: (C)

(C) Indicates Change.

STANDBY SERVICE - (CONTINUED)

Customers receiving Firm Standby Service shall pay a Standby Reservation charge as described below.

Monthly Reservation Charges (charged each month of the year):

Large Volume Customers

Customers who require natural gas service through a single meter for 20,000 Mcf annually or more:

$10.52 per Mcf of MDFR (D)(C)

Customers who require annual natural gas service of less than 20,000 Mcf:

Small Volume Customers (0 to 500 Mcf Annual Usage)

$1.84 per Mcf of throughput (D)

Medium Volume Customers (501 to 20,000 Mcf Annual Usage)

Low Load Factor Service

Firm Standby: $0.99 per Mcf of throughput (D)(C)

High Load Factor Service

Firm Standby: $0.54 per Mcf of throughput (D)(C)

A Medium Volume customer will be billed at the Low Load Factor Service Rate when the customer's annual system utilization factor (actual annual volume ÷ 100% annual system utilization volume) is not more than 50 percent. A Medium Volume customer will be billed at the High Load Factor Service rate when the customer's annual system utilization factor is more than 50 percent of the customer's 100% annual system utilization volume. System utilization factors will be based on Company estimates where historic data is not available.

The Reservation charges shall be redetermined annually during the course of the Company's 1307(f) proceeding.

A customer may discontinue Firm Standby Service, if the Company, in its sole discretion, can obtain any decrease in its transportation and storage entitlements or any combination thereof required to accommodate such transfer from Standby service and the customer provides written notice to the Company at least twelve months prior to the expiration date of the customer's Service Agreement.

Standby Reservation Charge Revenue shall be credited to Purchased Gas Cost for the purpose of determining the "E" factor. (C)

Per the settlement in Docket No. R-00038166, the Company has the ability to switch transportation customers to daily measurement or increase the cost recovery from these customers via a separate negotiated capacity charge.

(D) Indicates Decrease. (C) Indicates Change.

RIDER A - (Continued)

The "E" factor shall also provide for refund or recovery of amounts necessary to adjust for differences between actual over and under collections and estimated over and under collections included in the "E" factor of the previous PGC.

Interest shall be computed monthly at the appropriate rate as provided for in Section 1308(d) of the Public Utility Code from the month the over or under collection occurs to the effective month such over collection is refunded or such under collection is recouped.

Supplier refunds received applicable to PGC Rate Schedules will be included in the calculation of "E" with interest added at the annual rate of six percentum (6 percent) calculated in accordance with the foregoing procedure beginning with the months such refund is received by the Company.

For the purpose of computing monthly over and undercollections to be reflected in "E" the following will be deducted from Purchased Gas Cost:

1. Demand and reservation charges billed sales customers under Rate Schedule CSF and transportation customers with firm standby service under any applicable Delivery Service Rate Schedule. Such charges shall be based on the Company's cost of reserving firm pipeline services and redetermined annually during the course of the Company's 1307(f) filing to be effective during the ensuing PGC application period.

2. The commodity cost of gas applicable to contract sales and standby sales service as specified in Rate Schedules CSF, CSI, and applicable Delivery Service Rate Schedules.

"S" -- projected Mcf of gas to be billed under PGC Rate Schedules during the computation year.

"Purchased Gas" -- the volume of gas projected to be purchased by the Company and delivered to customers under PGC Rate Schedules, plus such portion of the company-used and unaccounted-for-gas as the Commission permits, including, but not limited to, natural gas, liquefied natural gas, synthetic gas, liquefied propane and naphtha.

"The Current PGC" -- is $11.28 per Mcf, comprised of a C factor of $10.54 (D)
and an E factor of $0.74. (D)

"Computation Year" -- the projected year during which the PGC will be in effect.

The application of the purchased gas cost shall be subject to continuous review and to audit by the Commission at such intervals as the Commission shall determine. The Commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the purchased gas cost and the charges included herein.

(D) Indicates Decrease.

RIDER B

TRANSPORTATION MIGRATION RIDER

I. This rider provides a method under 1307(f) of the Public Utility Code for recovery of the experienced net over/under collection of purchased gas costs as adjusted quarterly from ratepayers who shifted from the retail service to delivery service on or after the effective date of this rider. The Company may waive this rider, in whole or in part, for customers with competitive options.

II. The migration rider rate shall equal the current 1307(f) rate less the C-Factor (projected cost of gas) as approved in the Company's most recent annual Section 1307(f) natural gas cost proceeding, including all E-Factor adjustments to the rate resulting from the Company's quarterly recalculation of natural gas costs.

Revenue under this rider will be credited in the Company's 1307(f) mechanism.

III. This rider shall be applicable to Rate FDS, GDS and DDS customers for a period of one year from the date upon which the customer last shifted from the Company's retail service..

IV. Applicable Surcharges

	$ Mcf	
Rate Schedules FDS, GDS, DDS	$0.74	(D)

This rate will be recalculated as part of the 1307(f) proceedings and will be tracked monthly.

Reverse Migration Charge:

Customers returning to retail sales service, who have been receiving delivery service for a minimum of twelve consecutive months, are not subject to the E-Factor portion of the Company's purchase gas cost rate so long as they remain a retail sales service customer for a period of one year.

(D) Indicates Decrease.

Docket No. R-00061295
Item 53.64(c)(1)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(1) A complete list in schedule format of each spot and each long term source of gas supply, production, transportation and storage, used in the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, separately setting forth on a monthly basis the quantity and price of all gas delivered, produced, transported or stored, maximum daily quantity levels, maximum annual quantity levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take-or-pay provisions or minimum bill or take provisions of the purchases, balancing provisions and copies of Federal tariffs and contract provisions relating to the purchases – including demand and commodity components. With regard to each contemplated future source of supply, production, transportation or storage, during each of the next 20 months for each source, provide the name of the source, the maximum daily quantity, the maximum annual quantity, the minimum take levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and contractual or tariffed terms of the purchases, copies of applicable Federal tariffs, the expiration date of each contract, the date when each contract was most recently negotiated and the details of the negotiation – such as meeting held, offers made, and changes in contractual obligation – and whether current proceedings, negotiations, or renegotiations are pending before the Federal Energy Regulatory Commission, and the like, to modify the price, quantity or another condition or purchase, and if so, the details of the proceedings, negotiations, or renegotiations. Gas supply sources which individually represent less than 3.0% of the total system supply may be shown collectively, such as other local gas purchases.

Response:

I. See Section I; Part C, Sheets 2-3 and Part D, Sheets 2-4, which sets forth on a monthly basis the quantity and price of gas delivered for all sources of gas supply used in the past 14 months.

II. See Section I; Part B, Sheets 1-8, and Part C, Sheets 4-7 for the quantity, price and source of gas contemplated to be used during each of the next 19 months (March 2006 through September 2007).

III. See Item 53.64(c)(4) for all pending Federal Energy Regulatory Commission actions and dockets dealing with interstate capacity and gas supply.

Docket No. R-00061295
Item 53.64(c)(3)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(3) A complete listing of sources of gas supply, transportation or storage and their costs, including shut-in and curtailed sources of supply, both inside and outside this Commonwealth considered by or offered to the utility but not chosen for use during the past 12 months, which twelve month period shall end 2 months prior to the date of the tariff filing, and the reasons why the gas supply, transportation or storage was not selected for use as a part of the utility's supply mix. A similar listing of gas sources, transportation or storage and associated projected costs offered or considered but not chosen to meet supply for the next 20 months, along with reasons for non-selection.

Response: *Please see the attached.*

Month	Company	Volume	Pipeline	Access Area	Price	Reason	Date
January 2005	GRP	5,000	TETCO	WLA	$6.17	Price	01/01/05
	JC Energy	5,000	TETCO	WLA	$6.17	Price	01/01/05
	Frontera	5,000	TETCO	WLA	$6.16	Price	01/01/05
	BP	5,000	TETCO	STX	$5.93	Price	01/01/05
	BP	5,000	TETCO	WLA	$6.15	Requirements Filled	01/01/05
	BP	10,000	TETCO	ETX	$6.06	Price	01/01/05
	ChevronTexaco	5,000	TETCO	WLA	$6.15	Requirements Filled	01/01/05
	ChevronTexaco	5,000	TETCO	STX	$5.92	Requirements Filled	01/01/05
	ConocoPhillips	10,000	TETCO	M1	$6.30	Price	01/01/05
	GRP	5,000	TETCO	STX	$5.93	Price	01/01/05
	Total	5,000	TETCO	STX	$5.97	Price	01/01/05
	Total	10,000	TETCO	M1	$6.32	Price	01/01/05
	VPEM	5,000	TETCO	STX	$5.92	Price	01/01/05
	VPEM	5,000	TETCO	WLA	$6.15	Requirements Filled	01/01/05
	Anadarko	5,000	TETCO	WLA	$6.16	Requirements Filled	01/01/05
	BP	5,000	TETCO	ELA	$6.15	Price	01/01/05
	ChevronTexaco	5,000	TETCO	ELA	$6.16	Price	01/01/05
	ConocoPhillips	5,000	TETCO	ELA	$6.16	Price	01/01/05
	VPEM	5,000	TETCO	ELA	$6.16	Price	01/01/05
	Amerada Hess	5,000	TETCO	WLA	$6.15	Requirements Filled	01/01/05
	Amerada Hess	5,000	TETCO	ELA	$6.17	Price	01/01/05
	Noble	5,000	TETCO	ELA	$6.16	Price	01/01/05
	Total	5,000	TETCO	WLA	$6.21	Price	01/01/05
	Total	10,000	TETCO	ELA	$6.21	Price	01/01/05
	PPM Energy	10,000	TETCO	ELA	$6.26	Price	01/01/05
	Cinergy	5,000	TETCO	WLA	$6.37	Price	01/25/05
	Cokinos	5,000	TETCO	ELA	$6.43	Price	01/25/05
	Cokinos	5,000	TETCO	ELA	$6.49	Price	01/26/05
	Total	5,400	TETCO	WLA	$6.38	Price	01/27/05
	Cokinos	10,000	TETCO	ELA	$6.47	Price	01/27/05
	VPEM	10,000	Dominion	S. Point	$6.60	Price	01/29/05
	Cinergy	10,000	TETCO	ELA	$6.27	Price	01/29/05
February 2005	GRP	5,000	TETCO	WLA	$6.24	Price	02/01/05
	JC Energy	5,000	TETCO	WLA	$6.24	Price	02/01/05
	Frontera	5,000	TETCO	WLA	$6.23	Price	02/01/05
	BP	5,000	TETCO	STX	$6.00	Price	02/01/05
	BP	5,000	TETCO	WLA	$6.22	Requirements Filled	02/01/05
	BP	10,000	TETCO	ETX	$6.13	Price	02/01/05
	ChevronTexaco	5,000	TETCO	WLA	$6.22	Requirements Filled	02/01/05
	ChevronTexaco	5,000	TETCO	STX	$5.99	Requirements Filled	02/01/05
	ConocoPhillips	10,000	TETCO	M1	$6.37	Price	02/01/05
	GRP	5,000	TETCO	STX	$6.00	Price	02/01/05
	Total	5,000	TETCO	STX	$6.04	Price	02/01/05
	Total	10,000	TETCO	M1	$6.39	Price	02/01/05
	VPEM	5,000	TETCO	STX	$5.99	Price	02/01/05
	VPEM	5,000	TETCO	WLA	$6.22	Requirements Filled	02/01/05
	Anadarko	5,000	TETCO	WLA	$6.23	Requirements Filled	02/01/05
	BP	5,000	TETCO	ELA	$6.22	Price	02/01/05
	ChevronTexaco	5,000	TETCO	ELA	$6.23	Price	02/01/05
	ConocoPhillips	5,000	TETCO	ELA	$6.24	Price	02/01/05
	VPEM	5,000	TETCO	ELA	$6.23	Price	02/01/05
	Amerada Hess	5,000	TETCO	WLA	$6.22	Requirements Filled	02/01/05
	Amerada Hess	5,000	TETCO	ELA	$6.24	Price	02/01/05
	Noble	5,000	TETCO	ELA	$6.23	Price	02/01/05
	Occidental	5,000	TETCO	WLA	$6.18	Price	02/01/05
March 2005	GRP	5,000	TETCO	WLA	$6.26	Price	03/01/05
	JC Energy	5,000	TETCO	WLA	$6.26	Price	03/01/05
	Frontera	5,000	TETCO	WLA	$6.25	Price	03/01/05
	BP	5,000	TETCO	STX	$6.02	Price	03/01/05
	BP	5,000	TETCO	WLA	$6.24	Requirements Filled	03/01/05
	BP	10,000	TETCO	ETX	$6.15	Price	03/01/05
	ChevronTexaco	5,000	TETCO	WLA	$6.24	Requirements Filled	03/01/05
	ChevronTexaco	5,000	TETCO	STX	$6.01	Requirements Filled	03/01/05
	ConocoPhillips	10,000	TETCO	M1	$6.39	Price	03/01/05
	GRP	5,000	TETCO	STX	$6.02	Price	03/01/05
	Total	5,000	TETCO	STX	$6.06	Price	03/01/05
	Total	10,000	TETCO	M1	$6.41	Price	03/01/05

Month	Company	Volume	Pipeline	Access Area	Price	Reason	Date
	VPEM	5,000	TETCO	STX	$6.01	Price	03/01/05
	VPEM	5,000	TETCO	WLA	$6.24	Requirements Filled	03/01/05
	Anadarko	5,000	TETCO	WLA	$6.25	Requirements Filled	03/01/05
	BP	5,000	TETCO	ELA	$6.24	Price	03/01/05
	ChevronTexaco	5,000	TETCO	ELA	$6.25	Price	03/01/05
	ConocoPhillips	5,000	TETCO	ELA	$6.25	Price	03/01/05
	VPEM	5,000	TETCO	ELA	$6.25	Price	03/01/05
	Amerada Hess	5,000	TETCO	WLA	$6.24	Requirements Filled	03/01/05
	Amerada Hess	5,000	TETCO	ELA	$6.26	Price	03/01/05
	Noble	5,000	TETCO	ELA	$6.25	Price	03/01/05
April 2005	Exxon	5,000	TETCO	ELA	$7.2725	Price	04/01/05
	GRP	5,000	TETCO	ELA	$7.28	Price	04/01/05
	Cinergy	5,000	TETCO	ETX	$7.1500	Price	04/01/05
	Total	10,000	TETCO	WLA	$7.200	Price	04/01/05
	Total	5,000	TETCO	STX	$7.085	Price	04/01/05
	One Nation	10,000	TETCO	WLA	$7.180	Price	04/01/05
	JC Energy	5,000	TETCO	WLA	$7.210	Price	04/01/05
	JC Energy	5,000	TETCO	STX	$7.110	Price	04/01/05
	Anadarko	5,000	TETCO	WLA	$7.180	Price	04/01/05
	Cinergy	5,000	TETCO	STX	$7.105	Price	04/01/05
	Anadarko	5,000	TETCO	ETX	$7.12	Maintenance	04/01/05
	Cinergy	5,000	Dominion	S. Point	$7.68	Price	04/09/05
	BP	5,000	Dominion	S. Point	$7.675	Price	04/09/05
	NJR	5,000	Dominion	S. Point	$7.60	Price	04/12/05
	Eagle Energy	5,000	Dominion	S. Point	$7.61	Price	04/12/05
	Occidental	5,000	Dominion	S. Point	$7.62	Price	04/12/05
	Cinergy	5,000	Dominion	S. Point	$7.425	Price	04/20/05
	Cinergy	5,000	Dominion	S. Point	$7.52	Price	04/21/05
	Anadarko	10,000	TETCO	WLA	$6.7750	Price	04/22/05
	Cinergy	5,000	Dominion	S. Point	$7.800	Price	04/26/05
	One Nation	5,000	TETCO	WLA	$6.925	Price	04/27/05
May 2005	Exxon	5,000	TETCO	ELA	$6.7025	Price	05/01/05
	GRP	5,000	TETCO	ELA	$6.71	Price	05/01/05
	Anadarko	5,000	TETCO	ETX	$6.55	Maintenance	05/01/05
	Total	5,000	TETCO	STX	$6.45	Price	05/01/05
	Total	5,000	TETCO	WLA	$6.60	Requirements Filled	05/01/05
	ConocoPhillips	5,500	TETCO	STX	$6.630	Price	05/01/05
	One Nation	5,000	TETCO	WLA	$6.580	Requirements Filled	05/01/05
	Frontera	5,000	TETCO	STX	$6.40	Price	05/01/05
	Anadarko	5,000	TETCO	STX	$6.42	Price	05/01/05
	One Nation	5,000	TETCO	M1	$6.83	Price	05/01/05
	Frontera	5,000	TETCO	M1	$6.835	Price	05/01/05
	GRP	5,000	TETCO	M1	$6.830	Price	05/01/05
	Colonial	10,000	TETCO	M2	$7.020	Price	05/05/05
June 2005	Exxon	5,000	TETCO	ELA	$6.0725	Price	06/01/05
	GRP	5,000	TETCO	ELA	$6.080	Price	06/01/05
	Anadarko	5,000	TETCO	ETX	$5.92	Maintenance	06/01/05
	Anadarko	5,000	TETCO	STX	$5.90	Price	06/01/05
	Anadarko	7,500	TETCO	ETX	$5.98	Price	06/01/05
	JC Energy	5,000	TETCO	STX	$5.91	Price	06/01/05
	Anadarko	7,500	TETCO	ETX	$5.940	Price	06/01/05
	JC Energy	5,000	TETCO	STX	$5.9000	Price	06/01/05
	GRP	7,000	Dominion	S. Point	$6.49	Price	06/01/05
	Cinergy	10,000	TETCO	STX	$5.88	Price	06/01/05
	BP	10,000	TETCO	M1	$6.19	Price	06/01/05
	Anadarko	7,000	TETCO	ETX	$5.93	Price	06/01/05
July 2005	Exxon	5,000	TETCO	ELA	$6.9325	Price	07/01/05
	GRP	5,000	TETCO	ELA	$6.940	Price	07/01/05
	Anadarko	5,000	TETCO	ETX	$6.77	Maintenance	07/01/05
	Total	5,000	TETCO	STX	$6.73	Price	07/01/05
	Total	5,000	TETCO	M1	$7.06	Price	07/01/05
	Cokinos	5,000	TETCO	STX	$6.70	Price	07/01/05
	GRP	5,000	TETCO	STX	$6.705	Requirements Filled	07/01/05
	Occidental	7,000	TETCO	STX	$6.730	Price	07/01/05
	Cinergy	7,000	TETCO	STX	$6.740	Price	07/01/05
	Occidental	4,000	TETCO	ETX	$6.755	Requirements Filled	07/01/05

Month	Company	Volume	Pipeline	Access Area	Price	Reason	Date
August 2005	Exxon	5,000	TETCO	ELA	$7.6025	Price	08/01/05
	GRP	5,000	TETCO	ELA	$7.610	Price	08/01/05
	Anadarko	5,000	TETCO	ETX	$7.45	Maintenance	08/01/05
	Occidental	5,000	TETCO	STX	$7.40	Requirements Filled	08/01/05
	Occidental	5,000	TETCO	M1	$7.77	Requirements Filled	08/01/05
September 2005	Exxon	5,000	TETCO	ELA	$10.6325	Price	09/01/05
	GRP	5,000	TETCO	ELA	$10.640	Price	09/01/05
	Anadarko	5,000	TETCO	ETX	$10.65	Maintenance	09/01/05
	Frontera	5,000	TETCO	STX	$10.37	Requirements Filled	09/01/05
	Frontera	5,000	TETCO	M1	$10.79	Requirements Filled	09/01/05
	Total	5,000	TETCO	STX	$10.37	Requirements Filled	09/01/05
October 2005	Exxon	5,000	TETCO	ELA	$13.8825	Price	10/01/05
	GRP	5,000	TETCO	ELA	$13.890	Price	10/01/05
	Anadarko	5,000	TETCO	ETX	$13.71	Maintenance	10/01/05
	Southwestern	5,000	TETCO	M1	$13.46	Price	10/01/05
November 2005	Frontera	5,500	TETCO	STX	$12.49	Price	11/01/05
	Anadarko	5,500	TETCO	STX	$12.54	Price	11/01/05
	Anadarko	5,000	TETCO	ETX	$12.70	Requirements Filled	11/01/05
	Occidental	5,000	TETCO	ETX	$12.83	Requirements Filled	11/01/05
	BP	5,000	TETCO	WLA	$7.56	Requirements Filled	11/01/04
	BP	10,000	TETCO	ETX	$7.47	Price	11/01/04
	ChevronTexaco	5,000	TETCO	WLA	$7.56	Requirements Filled	11/01/04
	ChevronTexaco	5,000	TETCO	STX	$7.33	Requirements Filled	11/01/04
	ConocoPhillips	10,000	TETCO	M1	$7.71	Price	11/01/04
	GRP	5,000	TETCO	STX	$7.34	Price	11/01/04
	Total	5,000	TETCO	STX	$7.38	Price	11/01/04
	Total	10,000	TETCO	M1	$7.73	Price	11/01/04
	VPEM	5,000	TETCO	STX	$7.33	Price	11/01/04
	VPEM	5,000	TETCO	WLA	$7.56	Requirements Filled	11/01/04
	Anadarko	5,000	TETCO	WLA	$7.57	Requirements Filled	11/01/04
	BP	5,000	TETCO	ELA	$7.5625	Price	11/01/04
	ChevronTexaco	5,000	TETCO	ELA	$7.57	Price	11/01/04
	ConocoPhillips	5,000	TETCO	ELA	$7.575	Price	11/01/04
	VPEM	5,000	TETCO	ELA	$7.57	Price	11/01/04
	Amerada Hess	5,000	TETCO	WLA	$7.56	Requirements Filled	11/01/04
	Amerada Hess	5,000	TETCO	ELA	$7.58	Price	11/01/04
	Noble	5,000	TETCO	ELA	$7.57	Price	11/01/04
December 2005	Anadarko	5,500	TETCO	STX	$8.39	Price	12/01/05
	Occidental	5,000	TETCO	ETX	$10.38	Requirements Filled	12/01/05

Docket No. R-00061295
Item 53.64(c)(4)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(4) An annotated listing of Federal Energy Regulatory Commission or other relevant non-Commission proceedings, including legal action necessary to relieve the utility from existing contract terms which are or may be adverse to the interests of its ratepayers, which affect the cost of the utility's gas supply, transportation or storage which might have an impact on the utility's efforts to provide its customers with reasonable gas service at the lowest price possible. This list shall include docket numbers and shall summarize what has transpired in the cases, and the degree of participation, if any, which the utility has had in the cases. The initial list filed under this paragraph shall include cases for the past three years. Subsequent lists need only update prior lists and add new cases.

Response: See attached.

**2005 ACTIVITIES OF EQUITABLE GAS COMPANY
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
(February 16, 2006)**

Set forth below is a summary of activities of Equitable Gas Company ("EGC") in 2005 at the Federal Energy Regulatory Commission ("FERC" or "Commission").

1. *Equitrans, L.P.*, Docket Nos. RP04-203, *et al.*

Equitrans in these consolidated proceedings filed a number of general Natural Gas Act ("NGA") Section 4 rate increases covering different time periods.

EGC participated in virtually all of the numerous settlement conferences, Customer Group meetings and conference calls, and received and gave input respecting the multitude of draft settlement offers, all of which occurred in the period from May to December, 2005. These efforts resulted in Equitrans filing on December 9, 2005, an uncontested settlement resolving all issues in the proceeding. The settlement was certified to the Commission by the Presiding Judge on January 18, 2006, and the settlement is now pending before the Commission.

2. *Equitrans, L.P.*, Docket No. CP05-18-000

On November 18, 2004, FERC established this proceeding to conduct an inquiry in response to Equitrans' claim that a portion of its storage cushion gas has been lost due to migration. On December 2, 2004, EGC filed an intervention in this proceeding. EGC monitored this proceeding in 2005, including review of various storage reports filed over the course of the year by Equitrans.

3. *Texas Eastern Transmission, LP*, Docket No. RP05-137-000

EGC intervened in and has monitored this case, which involved Texas Eastern's filing of its semi-annual Electric Power Cost Adjustment. FERC accepted the filing by order of January 26, 2005.

4. *Texas Eastern Transmission, LP*, Docket No. RP06-113-000

EGC intervened in and monitored this proceeding, which involved Texas Eastern's filing to remove the five-year term matching cap from the ROFR bidding process in its tariff. By order of December 22, 2005, FERC accepted the filing, effective January 1, 2006.

5. *Texas Eastern Transmission, LP*, Docket No. RP06-30-000

EGC intervened in and has monitored this case, which was initiated by Texas Eastern's filing of revised tariff sheets proposing to remove the $25 per Dth limitation on the penalty provisions in its tariff. The Commission, by order of November 10, 2005, authorized the elimination of the penalty cap, effective November 14, 2005.

6. *Texas Eastern Transmission, LP*, Docket No. RP06-45-000

EGC intervened in and has monitored this proceeding involving Texas Eastern's filing of its Annual Applicable Shrinkage Adjustment and Interruptible Revenue Reconciliation Report. By order of November 30, 2005, FERC accepted the filing, effective December 1, 2005.

7. *Texas Eastern Transmission, LP*, Docket No. RP06-70-000

EGC intervened in and has monitored Texas Eastern's filing of proposed changes to the nomination procedures in Section 4 of the General Terms and Conditions of its tariff. The proposed changes were accepted by FERC order of November 22, 2005, effective December 1, 2005.

8. *Texas Eastern Transmission, LP*, Docket No. RP06-167-000

EGC intervened in and monitored this proceeding, which involved Texas Eastern's filing on December 30, 2005 of its semi-annual Electric Power Cost Adjustment. The Commission by order of January 25, 2006 accepted the filing, effective February 1, 2006.

Docket No. R-00061295
Item 53.64(c)(5)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(5)	A listing and updating, if necessary, of projections of gas supply and demand provided to the Commission for any purpose. In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable – including storage – from the utility to its customers under various circumstances and time periods.
Response:	Please see the attached.

Docket No. R-00061295
Item 53.64(c)(5)

FORM-IRP-GAS-2A: NATURAL GAS SUPPLY
TABLE 1: ANNUAL SUPPLY
REPORTING UTILITY: EQUITABLE GAS COMPANY
(volumes in MDth)

	Historical Data		Current Year	Three Year Forecast		
Index Year Actual Year	-2 2004	-1 2005	0 2006	1 2007	2 2008	3 2009
Gas Supply for Sales Service						
Columbia	-	-	-			
Texas Eastern (East Texas)	1,205	1,205	1,205			
Dominion South Point	-	-	-			
Texas Eastern (East La.)	1,960	1,960	1,960			
Texas Eastern (South Texas)	1,510	1,510	1,510			
Texas Eastern (West La.)	450	450	450			
Texas Eastern (M1)	-	-	-			
Texas Eastern (South Texas)	-	-	-			
Texas Eastern (West La.)	-	-	-			
Texas Eastern (East La.)	-	-	-			
Spot Purchases/ Other Supply Contracts	17,862	15,068	16,495	21,620	21,620	21,620
Storage Withdrawals (EQT/TCO/CNG)	9,294	11,572	12,385	12,385	12,385	12,385
LNG/SNG/Propane Purchases						
Company Production	-	-	-	-	-	-
Local Purchases	5,000	5,000	5,000	5,000	5,000	5,000
Exchanges with other LDC's						
Other (Off-System sales)	19,529	13,110	10,740	10,740	10,740	10,740
Total Gas Supply for Sales:	56,810	49,875	49,745	49,745	49,745	49,745
Total Transportation Service:	26,987	23,180	23,180	23,180	23,180	23,180
TOTAL SALES GAS SUPPLY AND TRANSPORTATION SERVICE	83,798	73,054	72,925	72,925	72,925	72,925
Deductions						
Curtailments						
Underground Storage Injections	9,396	10,207	12,385	12,385	12,385	12,385
LNG Liquefacation						
Sales to other LDC's						
Off-System Sales	19,529	13,110	10,740	10,740	10,740	10,740
Total Deductions:	28,925	23,318	23,125	23,125	23,125	23,125
NET GAS SUPPLY	*54,872*	*49,737*	*49,800*	*49,800*	*49,800*	*49,800*

Docket No. R-00061295
Item 53.64(c)(5)

Company Name: Equitable Gas Company
FORM-IRP-GAS-1A. Annual Energy Demand Requirements (January 1 through December 31)

(MDTH)

					Current Year	Three Year Forecast		
	Index Year:	-3	-2	-1	0	1	2	3
	Actual Year:	2003	2004	2005	2006	2007	2008	2009
	FIRM REQUIREMENTS							
01	Retail Residential	22,093	20,779	19,885	20,209	20,209	20,209	20,209
02	Retail Commercial	4,089	4,411	4,189	3,982	3,982	3,982	3,982
03	Retail Industrial	86	82	116	58	58	58	58
04	Electric power generation	0	0	0	0	0	0	0
05	Exchange w/other utilities	0	0	0	0	0	0	0
06	Unaccounted for	2,032	2,550	2,311	2,314	2,314	2,314	2,314
07	Company use	72	63	57	57	57	57	57
08	Other (Rate 8)	0	0	0	0	0	0	0
09	Subtotal Firm	28,373	27,885	26,558	26,620	26,620	26,620	26,620
	INTERRUPTIBLE REQUIREMENTS							
10	Retail (Rate 9)	0	0	0	0	0	0	0
11	Electric power generation	0	0	0	0	0	0	0
12	Company's own plant	0	0	0	0	0	0	0
13	Subtotal Interruptible	0	0	0	0	0	0	0
14	Subtotal Firm and Interruptible	28,373	27,885	26,558	26,620	26,620	26,620	26,620
	TRANSPORTATION SERVICE							
15	Firm							
	Residential	3,801	3,468	3,570	3,570	3,570	3,570	3,570
	Commercial	3,768	3,648	2,837	2,837	2,837	2,837	2,837
	Industrial	568	606	447	447	447	447	447
16	Interruptible							
	Residential	0	0	0	0	0	0	0
	Commercial	8,952	8,668	6,742	6,742	6,742	6,742	6,742
	Industrial	8,422	10,598	9,583	9,583	9,583	9,583	9,583
17	Electric power generation	0	0	0	0	0	0	0
18	Subtotal Transportation	25,512	26,987	23,180	23,180	23,180	23,180	23,180
19	Total Gas Requirements	53,885	54,872	49,737	49,800	49,800	49,800	49,800
20	Increase (Decrease)	2,262	987	(5,135)	62	0	0	0
21	Percent Change (%)	4.38%	1.83%	-9.36%	0.13%	0.00%	0.00%	0.00%
		51,780	52,259	47,369	47,429	47,429	47,429	47,429

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(6) Each Section 1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of gas supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

Response: Equitable purchases its gas supplies based on an acquisition strategy that minimizes gas purchase costs while assuring there is adequate, reliable supply. "Adequate and reliable" means that planning is based on assuring deliverability during peak demand periods under design day conditions. In addition, factors including historical dependability and reliability are considered. Finally, "adequate and reliable" means that the gas quality and the operating pressures are consistent with the Company's needs and qualitative standards.

Equitable purchases competitively priced gas supplies from the Southwest production areas utilizing various interstate pipeline facilities and from local Appalachian producers. The Company purchases, on an economic basis, a majority of the gas needed to meet peak demand requirements from the Southwest production areas. In addition, the Company has an aggressive local Appalachian production gas purchase strategy that is designed to attract new supplies to its system. The Company utilizes firm transportation service on the Texas Eastern, Dominion and Equitrans interstate pipeline systems to ensure this gas is delivered to its city-gate. Finally, the Company continues to aggressively re-negotiate gas supply contracts in an effort to provide service at the lowest possible cost consistent with its obligation to serve firm customers.

Equitable's Gas Acquisition & Management Department is responsible for all gas supply and planning functions. This department is adequately staffed with qualified and well-trained personnel who receive regular updates on conforming with the Company's least cost purchasing policy. In addition to their industry experience, personnel responsible for gas supply and planning attend seminars, conferences and short courses that address supply strategies and methodologies. Additionally, they communicate continuously with gas suppliers, producers, marketers and interstate pipeline representatives in matters pertaining to Equitable's fuel procurement policy. Furthermore, these personnel receive frequent updates of current trends and new developments within the natural gas industry.

Equitable has concentrated on diversifying its supply portfolio and purchasing from numerous sources to the extent such actions conform to the Company's acquisition goals. Gas supplies that are purchased from the Southwest production areas continue to be an essential part of Equitable's gas supply portfolio. These supplies are used not only to meet the requirements of customers during peak demand periods, but also to inject gas into storage during low demand periods. The Company has reduced the average length of its term contracts, in some instances for a three-month period (December-February). This will enable the Company to adjust its portfolio to market conditions. The shorter contract lengths also allow the Company to respond to any increased customer participation in its Choice Program. These firm supplies are used in conjunction with the interstate spot market to achieve a level of reliability necessary to meet Equitable's customer demand. Equitable continues to use the interstate spot market, on an economic basis, to either satisfy immediate demand requirements or for storage injection purposes.

Firm storage capacity is another essential element of Equitable's supply portfolio. Storage capacity is utilized to meet the winter peak requirements of the Company's largely residential, weather-sensitive customer base.

In addition, storage allows the Company to purchase supplies during the non-heating season to use later during winter peak periods when prices tend to increase. This strategy allows the Company to average its costs over a 12-month period rather than be subject to the vagaries of the market during periods when prices are escalating.

Equitable has a local Appalachian gas purchase strategy which consists of various pricing mechanisms, ranging from fixed pricing options to several different index pricing options. This strategy attempts to encourage the development of new, incremental supplies while also attempting to reduce the price volatility and operational uncertainties. Equitable utilizes short-term gas purchase agreements, long-term gas purchase agreements and existing life- of-the-well gas purchase agreements to provide a stable, long-term source of reliable supply.

Equitable's supply, transportation and storage portfolio minimizes the impact of fraud, non-performance or interruption of performance. The Company has a capacity release program which comports with the FERC's capacity release regulations and does not compromise in any way its least cost procurement policy. Capacity release programs provide the Company the opportunity to recover some of the fixed costs associated with holding firm interstate pipeline capacity.

Developments within the federal regulatory arena and the promulgation of FERC Order No. 636 directly impacted the availability and cost of natural gas to Equitable and its customers. The Company continually monitors new developments, such as FERC Order No. 637, in order to adequately manage its gas acquisitions, to take advantage of new opportunities and to minimize deliverability risks and/or price risks.

Docket No. R-00061295
Item 53.64(c)(7)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, *et seq.*
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(7) A list of off-system sales, including transportation, storage or capacity releases by the utility at less than the weighted average price of gas, or at less than the original contract cost of transportation, storage or capacity supplied to the utility for its own customers.

Response: The following is a summary, by month, of the off-system sales made during the twelve months ended December 2005.

	Volumes (Dth)	Revenues ($)	PBR1 ($)
January	1,227,707	8,511,464.81	291,145.81
February	1,501,760	10,406,821.74	324,793.88
March	1,796,117	12,452,109.58	211,832.30
April	1,248,738	9,349,464.89	201,983.83
May	1,347,243	9,412,547.04	94,229.78
June	1,048,875	7,490,027.05	129,279.10
July	1,692,237	12,479,976.90	126,143.02
August	724,466	5,852,157.00	93,061.27
September	648,724	5,150,974.32	14,434.32
October	716,641	5,566,033.65	-
November	350,600	3,561,968.43	-
December	807,135	10,646,785.41	-

The following is a summary, by month, of the capacity releases made during the twelve months ended December 2005 at less than the original contract cost of transportation, storage or capacity supplied to the utility for its own customers.

	Volumes (Dth)	Revenues ($)	PBR1 ($)
January	74,400	11,160.00	11,160.00
February	-	-	-
March	-	-	-
April	54,720	7,660.80	7,660.80
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October	18,600	2,790.00	-
November	1,190,000	166,005.00	-
December	1,550,893	207,561.28	-

Docket No. R-00061295
Item 53.64(c)(8)

EQUITABLE GAS COMPANY

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending September 30, 2007

Item 53.64(c)(8)	A list of agreements to transport gas by the utility through its system, for other utilities, pipelines, or jurisdictional customers including the quantity and price of the transportation.
Response:	All transportation customers are served under Rate FDS – Firm Delivery Service, Rate GDS – General Delivery Service, or Rate DDS – Daily Delivery Service. None of the customers is either a utility or a pipeline.

Equitable transported 23.2 Bcf of gas for the 12 months ended December 2005. Attached is a summary of the monthly volume of gas transported and the associated revenue for the 12 months ended December 2005.

Equitable's Tariff Gas PA PUC No. 22 contains the currently effective tariff pages of the Delivery Service Rate Schedules. Pricing information is included in the Rate section of the Delivery Service Tariff pages which are incorporated herein by reference.

Docket No. R-00061295

<u>EQUITABLE GAS COMPANY</u>

Attachment

Response to 52 PA Code Section 53.64(c)(8)

	Delivery Service	
	Volumes (Mcf)	Revenue $
January 2005	3,595,759	6,348,418
February	3,165,146	5,788,819
March	3,192,039	4,926,584
April	1,512,664	1,911,231
May	1,479,814	1,472,193
June	807,527	876,383
July	863,677	626,199
August	1,068,407	933,399
September	942,284	606,237
October	1,479,154	1,658,349
November	1,987,316	3,087,278
December	3,088,726	5,187,827
Total	23,182,512	33,422,918